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NATURAL GAS COFIRING PROMOTION ACT OF 1989

HEARING

BEFORE THE

SUBCOMMITTEE ON
ENERGY RESEARCH AND DEVELOPMENT

OF THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

ONE HUNDRED FIRST CONGRESS

SECOND SESSION

ON

S. 1848

NATURAL GAS COFIRING PROMOTION ACT OF 1989

MAY 8, 1990

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CONTENTS

Page

S. 1848 3

STATEMENTS

Bingaman, Hon. Jeff, U.S. Senator from New Mexico 6
Blake, Francis S., attorney, Swidler & Berlin 102
Burns, Hon. Conrad, U.S. Senator from Montana 71
Domenici, Hon. Pete V., U.S. Senator from New Mexico 71
Ford, Hon. Wendell H., U.S. Senator from Kentucky 1
Gentile, Robert H., Assistant Secretary for Fossil Energy, Department of Energy 10
Johnston, Hon. J. Bennett, U.S. Senator from Louisiana 72
Maassel, Mark T., manager, environmental programs, Northern Indiana Public Service Co. 133
Roberts, William J., legislative director, Environmental Defense Fund 114
Schmalensee, Richard, member, Council of Economic Advisers, accompanied by Jack S. Siegel, Gregory B. Foote, and Howard Gruenspecht 83
Siegel, Jack S., Deputy Assistant Secretary, Coal Technology, Department of Energy 6
Webb, David O., senior vice president, policy and regulatory affairs, Gas Research Institute 27
Winberg, Steven E., manager of cofiring development, Consolidated Natural Gas Co., on behalf of the American Gas Association and the Interstate Natural Gas Association 44

APPENDIXES

APPENDIX I

Responses to additional questions 163

APPENDIX II

Additional material submitted for the record 245

NATURAL GAS COFIRING PROMOTION ACT OF 1989

TUESDAY, MAY 8, 1990

U.S. SENATE,
SUBCOMMITTEE ON ENERGY RESEARCH AND DEVELOPMENT,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The subcommittee met, pursuant to notice, at 2:18 p.m., in room SD-366, Dirksen Senate Office Building, the Hon. Wendell H. Ford, presiding.

OPENING STATEMENT OF HON. WENDELL H. FORD, U.S. SENATOR FROM KENTUCKY

Senator FORD. Good afternoon, ladies and gentlemen.

I am pleased to be here today to chair the hearing on S. 1848, the Natural Gas Cofiring Promotion Act. This bill was introduced last fall by Senator Bingaman and myself, and Senator Bingaman is here.

As we move into the 1990s, we are seeing the greening of America. Concern over the state of the environment is growing. For the first time in a decade, Congress will enact amendments to the Clean Air Act.

The impact of any legislation passed will be far-reaching. It is important that we make our environmental gains in the context of a broader energy and economic future. We must further the goal of using our natural resources wisely. We must place additional emphasis on energy, research and development. The technological advances of the future must come from the R&D of today.

Gas cofiring is an example of a technological advance that should be pursued. This technology allows us to meet our energy needs cleanly with domestic resources and at a relatively low capital cost compared to the alternatives. Gas cofiring technologies show promise, but more R&D is necessary to fine tune the results. S. 1848 allows such a fine tuning to occur.

Our first panel of experts will provide the subcommittee with an update on the status and the performance of cofiring technology. It is my hope that they will address the need for and the scope of additional R&D such as that authorized by this bill.

However, even if the R&D is conducted the value of what we learn may not be realized. Regulatory barriers are being constructed that will make it difficult, if not impossible, to bring this technology and others to the marketplace. I am concerned that the EPA so-called WEPCO policy may be such a barrier.

Others, including the Department of Energy, believe that a clarification of WEPCO is necessary. This applies not only for gas cofiring technologies but for the success of the clean coal technology program as well.

EPA has promised to put forth an interim policy on WEPCO. We have not seen that happen yet. In addition, although the Senate-passed Clean Air Bill clarifies the WEPCO issue somewhat, it does not go far enough. A barrier such as WEPCO must be removed if we are to move ahead with our energy and our environmental policies. After all, a policy is only as good as the ability to implement it successfully.

A second panel of witnesses will be addressing EPA's WEPCO policy and its effect on energy production and environmental goals. I hope to learn through this panel what the barriers are, and how they might be removed.

Senator Bingaman, we are delighted that you are here. If you have a statement, we will be glad to entertain it at this time.

[The text of S. 1848 follows:]

101ST CONGRESS
1ST SESSION

S. 1848

To establish a research and demonstration program to promote cofiring of natural gas and coal in certain boilers and to provide Federal funding to carry out the program.

IN THE SENATE OF THE UNITED STATES

NOVEMBER 7 (legislative day, NOVEMBER 6), 1989

Mr. BINGAMAN (for himself and Mr. FORD) introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

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A BILL

To establish a research and demonstration program to promote cofiring of natural gas and coal in certain boilers and to provide Federal funding to carry out the program.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the "Natural Gas Cofiring Promotion Act of 1989".

SEC. 2. FINDINGS.

The Congress recognizes that—

(a) coal is an enormous domestic resource;

(b) certain harmful emissions from the combustion of coal will limit the percentage of the resource base which is deemed "usable";

(c) natural gas is an abundant domestic resource that has superior environmental qualities;

(d) certain technologies combine natural gas with coal in order to reduce sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions, particulates and carbon dioxide (CO_2) emissions from the combustion of coal; and improves the operating efficiency of some boilers by reducing slagging;

(e) certain technologies offer the potential to extend the usable coal resource base in the United States; and

(f) the United States will continue to rely on domestic coal as a primary fuel in electric generation.

Therefore, it is in the national interest to encourage the utilization of those natural gas technologies that reduce SO_2 and NO_x emissions resulting from the combustion of coal.

SEC. 3. DEFINITIONS.

For the purposes of this Act—

(a) the term "cofiring" means the injection of natural gas and pulverized coal into the primary combustion zone of an electric utility or an industrial boiler and shall include gas reburn technologies;

(b) the term "gas reburn" means the injection of natural gas into the upper furnace region of an electric utility or an industrial boiler to produce a fuel-rich zone thereby reducing nitrogen oxide emissions; and

(c) the term "Secretary" means the Secretary of Energy.

SEC. 4. RESEARCH AND DEMONSTRATION PROGRAM.

(a) The Secretary shall establish and carry out a program of research, development and demonstration of cofiring in utility and large industrial boilers in order to determine optimal natural gas injection levels for both environmental and operational benefits.

(b) The Secretary shall provide financial assistance under this section to appropriate parties for the research, development and demonstration of cofiring technologies.

(c) The Secretary shall not finance more than 50 per centum of the total costs of a cofiring technology projected selected for financial assistance under this section as estimated by the Secretary as of the date of award of financial assistance.

(d) There is authorized to be appropriated to the Secretary not more than $9,000,000 for each of the fiscal years 1991, 1992 and 1993 for purposes of this section.

STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

Senator BINGAMAN. Well, thank you, Mr. Chairman.

I appreciate you having the hearing, and of course, I am very pleased to be an original cosponsor of this bill with you. I think this is an important issue, and it is a way that we can facilitate use of coal and use of natural gas. And I think, clearly, this WEPCO issue is one that we do need to have good testimony on today.

The information I have is that the present policy does create a disincentive for modifications that are needed in many of these plans, and accordingly, we need to find a way to deal with that.

So thank you very much for holding the hearing, and I will just put the rest of my statement in the record.

[The prepared statement of Senator Bingaman follows:]

PREPARED STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

Thank you, Mr. Chairman, for calling today's hearing on S. 1848, the "Natural Gas Cofiring Promotion Act." I was proud to join you as an original sponsor and co-author of this legislation to provide incentives for the demonstration of natural gas cofiring technologies.

With the Senate's passage of amendments to the Clean Air Act, the need to demonstrate and deploy cofiring technologies is more important today than when we introduced this bill last fall. Basic cofiring can be an important bridge technology for electric utilities to comply with emissions reductions required in Phase I of the clean air legislation. And, if they can be brought to commercial maturity in time, advanced cofiring technologies may offer a cost-effective means for utilities to comply with Phase II emissions reductions.

This last point highlights the importance of S. 1848. The demonstration of advanced natural gas cofiring technologies must be accelerated so that they can be part of utilities' strategies for compliance with Phase II emissions reductions.

I am glad that the subcommittee has chosen to use this hearing as a chance to focus on the so-called WEPCO issue. There is great concern that EPA's WEPCO policy will frustrate the allowance trading scheme under the amendments to the Clean Air Act.

WEPCO is not only a clean air issue. It is also an energy issue. EPA's WEPCO policy creates a disincentive for modifications that increase electric power plant efficient. WEPCO also discourages efforts to restore and maintain generating capacity and reliability.

Along with Senators Bumpers and Breaux, I sponsored a WEPCO amendment to the Senate clean air legislation. It is clear, however, that a more comprehensive WEPCO fix is needed. The record established by today's hearing can provide guidance for the clean air conferees to find a WEPCO fix that properly balances the need for clean air, cost-effective emissions reductions, and sound energy policy.

Senator FORD. The first panel will consist of Jack S. Siegel, Deputy Assistant Secretary, Office of Coal Technology, the Department of Energy; David O. Webb, Senior Vice President, Policy and Regulatory Affairs, Gas Research Institute; and Steven A. Winberg, Manager, System Co-firing Marketing Development, Consolidated Natural Gas Service Company.

Gentlemen, we are delighted to have you. If you want to highlight your statement, with the balance to be put in the record in full, and then we get to questions.

We will first hear from Mr. Siegel.

STATEMENT OF JACK S. SIEGEL, DEPUTY ASSISTANT SECRETARY, COAL TECHNOLOGY, DEPARTMENT OF ENERGY

Mr. SIEGEL. Thank you, sir.

This afternoon I am substituting for Robert Gentile, who is the Assistant Secretary for fossil energy. He is unable to be here today because of illness. Mr. Gentile's testimony has been submitted for the record, and with your permission, I would like to briefly highlight only a couple of its key points.

Senator FORD. You may proceed.

Mr. SIEGEL. As should be apparent from the formal statement, the Department of Energy recognizes the potentially important benefits that can come from the cofiring of natural gas with coal. Those benefits can be both environmental and operational.

Tests conducted both in research facilities and at commercial plants show that the dual firing of gas and coal can effectively reduce base line emissions of sulfur dioxide and nitrogen oxide pollutants. Seasonal firing of natural gas, perhaps as much as 20 percent of the total fuel input, can also be effective in reducing sulfate and nitrate deposition during summer months. This can be especially important, because deposition often increases in these months due to summer storm activity.

Operational benefits can take several forms. Injecting natural gas can help stabilize burners firing difficult fuels; boiler deratings can be lessened, combustion efficiency can be improved, and overall reliability can be increased.

As indicated in the formal testimony, cofiring is one of two basic techniques for the dual use of coal and natural gas in coal-fired boilers. Cofiring directly substitutes one fuel, such as natural gas, for a portion of the coal in a boiler's primary combustion zone.

The other technique, called reburning, divides the furnace into two distinct combustion zones. Coal continues to be burned in the lower zone, while natural gas is fired in the upper regions of the boiler, primarily to create a zone in which nitrogen oxide pollutants are reconstituted into environmentally benign molecular nitrogen.

Cofiring is not a new technology, nor does it require significant technical advancements. As I have indicated in the formal testimony, many utilities already have short-term experience, because they use gas cofiring during start-up or on an intermittent basis to reduce emissions or improve operations.

What is needed today is the operational confidence that comes from longer-term, well-documented cofiring operations. Some of this documentation has been developed through privately sponsored test programs. DOE is planning to augment these efforts with specific cofiring tests on two commercial boilers, one owned jointly by ALCOA and Southern Indiana Gas and Electric Company, the other owned solely by ALCOA.

Gas reburning, by contrast, is still an evolving technology. Whereas cofiring uses existing boiler features, reburning requires modifications to the boiler. The first commercial-scale experience in this technology in the U.S. will likely come from the Federal programs—both our coal research program and the larger-scale clean coal technology demonstration program.

As described in the formal statement, we have several variations of the reburning concept in the development or demonstration phase. Some projects involve reburning alone; others integrate reburning with sorbent injection to provide greater sulfur dioxide re-

ductions or with low NO_x burners to provide greater nitrogen oxide reductions. And one project is intended to show that reburning is not just confined to natural gas but instead can use coal as the reburned fuel.

The attractiveness of the dual firing of coal and natural will, of course, ultimately depend on the regulatory climate affecting utilities, the ability of the gas industry to deliver sufficient quantities of natural gas to utilities, and obviously the cost. Each of these factors will likely be very site specific.

I might say at this point, Mr. Chairman, that discussions we had with your staff yesterday raised questions regarding the Department's view of the issue of supply versus the issue of deliverability. Let me ensure that there is no misunderstanding on this point.

As page 11 of Mr. Gentile's statement says, the Department is confident that the United States has a sufficiently large natural gas resource base to meet any new demand resulting from gas cofiring. The questions have been focused more on pipeline capacity and deliverability. As the formal statement indicates on page 12, several analyses have shown that there appears to be sufficient pipeline capacity for cofiring the largest SO_2 emitters with about 20 percent gas during the summer months and with about 10 percent gas year round.

Higher year-round rates, however, could contribute to some regional shortfalls in pipeline capacity. And cofiring of all coal-burning boilers at a 10 percent input level could create pipeline capacity constraints by the year 2000.

The issue of gas deliverability, therefore, could be especially important in determining the extent to which gas cofiring can or will be used in the utility industry. Recently, Mr. Chairman, the Department joined the Federal Energy Regulatory Commission in a study of the Nation's ability to deliver natural gas from the well head to the burnertip.

One of the key objectives will be to assess the accuracy and utility of currently available information on deliverability. We need to know what we can do or should do to increase the credibility and timeliness of current information being used to measure deliverability.

A key starting point will be the experience of last winter. By this fall, we will have an initial snapshot of last winter's situation and hopefully some useful recommendations that could improve information collection and processing. We will then be in a better position to develop a comprehensive assessment of how much gas can be delivered on a regional and national level under various market and weather conditions.

The schedule for a final product, obviously, will depend largely on what Phase I of the study determines. But we would hope to have a final product by the fall of next year.

In conclusion, Mr. Chairman, the Department of Energy embraces the concept of dual firing of natural gas and coal, where it makes technical and economic sense. And we believe many utilities will find that it makes sense for individual plants. But in evaluating S. 1848, we must ask ourselves whether the additional funding provided under the bill would be a useful Federal expenditure.

Our concern is that, given other budget priorities, the funding would likely duplicate ongoing efforts. Consequently, we must oppose enactment of S. 1848. We believe the more appropriate government role is to complete those demonstrations already begun and to focus on resolving regulatory questions concerning the transportation and use of natural gas in utility boilers.

This completes my opening statement. I would be pleased to answer any questions you or other members of the Subcommittee may have.

Thank you.

[The prepared statement of Mr. Gentile follows:]

Statement of
Robert H. Gentile
Assistant Secretary for Fossil Energy
U.S. Department of Energy
before the
Subcommittee on Energy Research and Development
Senate Energy and Natural Resources Committee
May 8, 1990

Mr. Chairman, thank you for inviting me to discuss information relevant to S.1848 dealing with the cofiring of coal with natural gas.

The proposed legislation correctly recognizes the advantages or potential advantages which can accrue from the simultaneous burning of coal and natural gas in coal-fired steam generators. These advantages are being investigated by the U.S. Department of Energy in consort with the private utility sector and the gas industry. However, while we support the increased use of natural gas as an important part of both our national energy and environmental policies and we embrace the concept of cofiring, S. 1848 seems duplicative of ongoing government and privately financed efforts, many of which are described in this testimony. Therefore, the Department must oppose this legislation.

Cofiring and Reburning Defined

Coal-gas cofiring refers to the injection of natural gas with pulverized coal into the primary combustion zone of a boiler. Because gas contains no sulfur or fuel-bound nitrogen, and less carbon than coal, emissions of these pollutants as oxides are reduced as gas is substituted for some of the coal.

2

Cofiring is not a new technology, but efforts to establish the optimal quantities of natural gas for both environmental and operational benefits are relatively recent.

Gas reburn is the injection of natural gas into the upper furnace region of a boiler to produce a fuel-rich zone in which the oxides of nitrogen (NO_x) are reduced to molecular nitrogen. In effect, the boiler is divided into primary and secondary combustion zones, with sufficient time in the zones to complete combustion and to reduce the NO_x to nitrogen.

Potential Advantages of Dual-Fuel Firing

Both cofiring and reburning result in the reduction of emissions of sulfur dioxide (SO_2) and NO_x. The SO_2 reductions result from the substitution of natural gas for coal. With the addition of 10% to 20% of natural gas, reburning can reduce 50% - 80% of the NO_x emissions. Cofiring is expected to remove 15% - 30% of the NO_x for the same 10% to 20% of natural gas used. In addition, cofiring can improve boiler plant operations in several ways. It:

- helps to stabilize burners firing difficult fuels;
- overcomes deratings caused by equipment malfunctions and capacity limitations;
- improves combustion efficiency by lowering excess air requirements and increasing carbon burnup;

- improves load-following characteristics;
- increases reliability and availability by minimizing corrosion, slagging and fouling;
- allows more rapid startup;
- provides better control of boiler parameters; and
- increases fuel flexibility.

Co-Firing

Unlike reburning, which involves the creation of two distinct combustion zones, cofiring is the direct substitution of one fuel for another. Cofiring natural gas with coal is not a new concept, as numerous utilities have used this mode during startup or steady load to reduce emissions or acquire operational benefits. However, it was not until 1986 that results were documented from a cofiring test program at the Cheswick Station of the Duquesne Light Company.

The concept of cofiring is simple to apply because it utilizes existing furnace features -- warm-up guns and ignitors -- without requiring furnace modifications. This was the case at Duquesne's Cheswick Station, where the unit was a tangentially-fired boiler of 570 megawatts (MW).

As one might expect, the minimum reductions in SO_2 and NO_x are directly related to the proportion of the coal displaced by natural gas. Besides the reduced inputs of fuel-bound sulfur and nitrogen, excess air is lower for gas,

as is the combustion temperature, so the amount of NO_x from nitrogen fixation is somewhat reduced.

Some interesting results were obtained from the Cheswick tests. When gas was fired through the warm-up guns, SO_2 emissions decreased in proportion to the percentage of gas heat input. However, when natural gas was fired through the ignitors, SO_2 emissions were reduced from 1 to 12%, using only 1 to 3% natural gas. The higher up the ignitor level used, the greater the reduction of SO_2. These sulfur capture data have not been explained fully, but it is believed that ash constituents such as calcium, iron and magnesium were involved in these SO_2 reductions.

Gas does not introduce fuel-bound nitrogen into the combustion process, so its substitution eliminates the NO_x generation associated with the organic nitrogen in the coal it displaces. Further, NO_x can be reduced additionally because a gas-supported burn requires less excess oxygen which reduces nitrogen fixation from combustion air. By biasing fuel (gas) distribution and reducing excess air at Cheswick, a 25% reduction in NO_x was achieved when cofiring 6 to 12% natural gas.

There are important differences among boiler operations with respect to duplicating the Cheswick results with other boiler plants. There are different types of boilers and different designs within each class of boilers. Boilers are designed for specific coals or types of coals so combustion, heat release patterns, steam heating circuits, and allowances for slagging and

fouling vary among boilers within a single class, e.g., tangentially-fired boilers. Besides the differences in fuel and combustion characteristics, the chemical and physical behavior of the ash-forming mineral matter varies among coals. Thus, it would be unreasonable to expect the Cheswick results to be applicable to all other boiler installations.

In the fall of 1989, Public Service Co. of Oklahoma (PSO) completed the first phase of a test program to explore cofiring as a means of alleviating slagging problems on two of their 450 megawatt, tangentially-fired units. Data analyses and interpretation are not complete, but results from tests on the units indicate that:

- wall cleanliness was better than design, in spite of coal ash properties which were significantly more conducive to slagging;

- cofiring reduced emissions of SO_2; leveraged reductions of 20% were obtained with 10% cofiring; and

- NO_x essentially was unchanged, probably because higher combustion temperatures promoted the formation of thermal NO_x which offset the inherently lower fuel-derived NO_x.

DOE Program. In response to an unsolicited proposal, DOE is planning to participate in cofiring tests on a wall-fired pulverized coal boiler. The program objective is to determine and document the technical and economic

benefits of cofiring natural gas with coal for environmental and operational improvements in wall-fired boilers. The four specific areas to be addressed are: (1) the "strategic" use of cofiring to reduce short-term SO_2 emission peaks; (2) the use of cofiring to reduce slagging; (3) the use of gas to maintain capacity during coal mill outages; and (4) the use of cofiring to reduce carbon carryover in the flyash.

Testing will be performed on a 300 megawatt boiler and a 144 megawatt boiler located in Warrick County, Indiana. The 300 megawatt boiler is owned by the Aluminum Co. of America (ALCOA) and Southern Indiana Gas and Electric Co. (SIGECo), and the smaller unit is owned by ALCOA. In addition to ALCOA and SIGECo, project participants are the Gas Research Institute (GRI), Radian Corp., and the gas pipeline distribution company. Negotiations are in progress and the contract should be signed early in FY91.

Gas Reburn

Gas reburn is more difficult to implement in a coal-fired boiler. Whereas cofiring takes advantage of existing boiler features, gas reburn requires boiler modifications. Reburning essentially is a combustion modification process which divides the furnace into two combustion zones. The secondary combustion zone is operated in an oxygen deficient or reducing mode which generates hydrocarbon radicals. These radicals react with NO_x formed in the primary combustion zone and reduce the NO_x to molecular nitrogen. Overfire air is added above the secondary combustion zone to complete the combustion.

7

Gas reburn is expected to achieve at least a 50% reduction in NO_x with up to 20% of the coal displaced with gas. Creation of the secondary combustion zone requires penetration of the boiler furnace with fuel injectors and ports for the overfire air. Gas reburn appears to be suited to any type of combustion system, but is particularly well suited to cyclone burners as these units do not lend themselves to burner modifications to control NO_x.

The concept of NO_x reduction by flames has been known for over a decade. Although the initial fundamental studies were carried out in the United States, reburning technology was developed in Japan and currently is being evaluated in the U.S. and Germany.

Development of gas reburning in conjunction with sorbent injection also is underway. Gas reburning-sorbent injection, or GRSI, is an integration of two developmental technologies: reburning for NO_x control and sorbent injection for SO_2 control. GRSI involves gas reburning and the injection of low-cost, calcium-based sorbents at one or more locations as the combustion gases pass from the radiant furnace through the convective passes to the air heater. Calcium oxide reacts with SO_2 to produce solid calcium sulfate which can be removed together with the flyash in an electrostatic precipitator or bag filters.

DOE Program. The DOE is involved in four reburning projects through the Coal Research and Development Program and the Clean Coal Technology (CCT) Program.

The R&D project involves the installation and operation of a reburning system at Ohio Edison's 108 MW Unit 1 at Niles, Ohio. Niles Unit #1 is a coal-fired cyclone boiler whose design traditionally produces high levels of NO_x emissions. Reburning technology represents an effective low cost combustion modification that can reduce NO_x emissions from coal-fired cyclone boilers. In this project, natural gas will replace 15-20% of the coal energy input, resulting in NO_x reductions of approximately 50%. The project, now estimated to cost $10.5 million, was initiated in 1987 by the U.S. Environmental Protection Agency when Combustion Engineering (CE) was awarded a contract to demonstrate the reburning technology. Since then, the project has attracted participation by DOE, the Electric Power Research Institute, the Gas Research Institute, Consolidated Natural Gas, the Ohio Coal Development Office, and Ohio Edison. DOE is funding its share of the project through a $2.5 million interagency agreement with EPA. CE will complete installation of the reburning system by June 26, 1990, and begin parametric testing to be followed by a six-month long-term test. The project is expected to be completed in the spring of 1992.

Three projects will be conducted as part of the CCT Program. The first project, selected in the first round of CCT competition (CCT-1), involves gas reburning and sorbent injection. Energy and Environmental Research (EER) will conduct two full-scale utility demonstrations to show that the combination of "gas reburning" and "sorbent injection" can reduce NO_x and SO_2 emissions from pre-New Source Performance Standards boilers by 60% and by 50%, respectively. SO_2 control will be achieved through the injection of sorbent in the upper

furnace. The technology will be demonstrated on an Illinois Power tangentially-fired 80 megawatt boiler at Hennepin, Illinois, and on a City Water Light and Power 40 megawatt cyclone-fired boiler in Springfield, Illinois. Demonstration at a third site -- a wall-fired unit in Bartonville, Illinois -- has been placed on hold due to cost growth in the project. The project is scheduled for completion in early 1993 at Hennepin and Springfield. Design work has been completed for both sites and construction activities are beginning.

The process and equipment easily could be retrofitted to most U.S. utility boilers. If the technology is widely adopted following demonstration, it would enhance the use of high-sulfur U.S. coals and represent a significant step toward the reduction of SO_2 and NO_x.

Energy and Environmental Research (EER), one of the firms selected in the CCT-3 competition, will demonstrate combined technologies of gas reburning and low NO_x burners (GR-LNB) on Public Service of Colorado's (PSCo) Cherokee Station Unit 3, a 172 megawatt front wall-fired utility boiler. Colorado bituminous coal containing about 0.4% sulfur will be used. The objective of this project is to achieve approximately 75% NO_x control on a wall-fired boiler. The technology is of a type that can be easily retrofitted and has low capital cost. In conjunction with this project but separately funded, PSCo intends to install a sorbent injection system based on sodium. This

project therefore provides the potential opportunity to evaluate the integration of three advanced emission control technologies--gas reburning, low NO_x burners and sorbent injection--in a single demonstration.

Further, fuels other than natural gas can be used for reburning. As an example, Babcock and Wilcox was selected under CCT-2 to demonstrate that coal reburning could be used for control of NO_x emissions from cyclone boilers. Reburning depends on the creation of a secondary combustion-reducing zone and the chemistry of the process does not depend on a particular fuel. This project seeks to show that coal can be used as a reburning fuel for reducing NO_x in a coal-fired cyclone boiler. Reburning is the only in-furnace NO_x control technology that has been shown to be technically feasible for cyclone boilers. A coal-reburning retrofit will be applied to Wisconsin Power & Light Company's Nelson Dewey Plant Unit No. 2 located along the Mississippi River in Cassville, Wisconsin. The demonstration seeks to achieve a 50% NO_x reduction with no resultant decrease in boiler efficiency. The reburning technology is expected to be applicable to all cyclone boilers larger than about 80 megawatts.

Negotiations on this project have been completed and the required report has been delivered to Congress. The Cooperative Agreement was signed by DOE last month. Activities have begun on design and permitting work, which should be completed by February 1991. Installation and start-up are planned from that time until October 1991. The project is scheduled to be completed in March 1993.

Additionally, under the Coal R&D Program, DOE is pursuing the following supporting research activities:

- Energy and Environmental Research Corporation (EER) is investigating the physical and chemical constraints that prevent attainment of 85% NO_x reduction;

- The University of Arizona is conducting studies to define the optimum configuration for NO_x abatement by distributed secondary fuel addition; and

- Louisiana State University is conducting studies to determine the interactions between NO_x and fuel-derived hydrocarbons.

Gas Availability

DOE is confident that there are sufficient natural gas resources to meet any new demand resulting from increased use of gas for cofiring. It is now generally agreed that the U.S. is endowed with a large natural gas resource base. In a 1988 study, DOE estimated that the Nation has a 35-year supply of natural gas at consumption rates of 17 trillion cubic feet a year, and at prices of $3.00 per thousand cubic feet or less. At prices in the range of $3.00-$5.00 per thousand cubic feet, our supplies would extend far longer.

While the resource base is large, the delivery infrastructure from wellhead to burnertip must be sufficient to assure that reliable supplies of natural gas are available to consumers.

Several studies have analyzed the impacts of cofiring on natural gas pipeline capacity. These studies involved the American Gas Association (AGA), the Interstate Natural Gas Association of America, the National Petroleum Council and DOE. General findings from these studies were:

- o there appears to be sufficient pipeline capacity for cofiring the largest SO_2 emitters with about 20% gas additions during the summer months;

- o year-round cofiring of the largest emitters at a 10% input rate should not create pipeline capacity problems; higher input rates may contribute to some regional shortfalls in pipeline capacity; and

- o mandated cofiring of all coal-burning boilers at a 10% input level could create pipeline capacity constraints by the year 2000 because the gas delivery system would be fully loaded or possibly even overloaded; this would be particularly true in regions that contain large numbers of coal-fired utility boilers.

The economic impacts of mandated cofiring are difficult to accurately predict. Mandated cofiring of all coal-fired boilers would increase the demand for gas and therefore increase gas prices. Since gas cofiring would only be used when

it is the most economic compliance option, higher gas prices would be offset by electricity prices that would be lower than if a more expensive compliance option were chosen.

The attractiveness of cofiring, however, is not dependent upon the availability of natural gas throughout the year. Even if it is not available during the peak period of gas consumption, for example in the winter, a power plant using cofiring could still comply with proposed environmental regulations since the regulations are based on annualized emissions reductions.

Costs

Estimated costs for cofiring and reburning will vary based on the type of boiler and assumptions -- mainly future gas prices -- used in the estimates. DOE estimated the cost of cofiring in the 50 coal-fired powerplants which are the largest emitters of SO_2. Costs were based on 10% gas cofiring to yield 10% and 25% reductions in SO_2 and NO_x respectively. At a differential of $1 per million Btu between gas and coal, costs ranged from about $200 to $600 per ton of combined SO_2 and NO_x removed.

AGA compared the control options on the basis of the combined cost-per-ton of SO_2 and/or NO_x removed from a 500 megawatt existing coal-fired powerplant in constant levelized 1988 dollars. Costs were based on 15-year plant life and AGA price projections for coal and natural gas. AGA estimates the cost of

cofiring at $225 per ton of SO_2 plus NO_x removed (for 10% gas cofiring which gives SO_2 and NO_x reduction of 12% and 25%, respectively). Reburning costs are estimated at $325 per ton SO_2 and NO_x, and with sorbent injection the cost increases to $485 per ton. For comparison, flue gas desulfurization (scrubber) costs are $470 per ton, with no NO_x reduction, and selective catalytic reduction (SCR) for NO_x is estimated at $3120 per ton.

Cost estimates by DOE and Stearns-Rogers for EPRI show that reburning and SCR costs for a tangentially-fired boiler are $1,900-$2,400 per ton and $1,800-$2,500 per ton of NO_x removed, respectively. An EPA analysis of gas reburning for cyclone boilers shows costs of $800-$1,200 per ton of NO_x removed, based on a cost differential of $2 per million Btu between gas and coal.

Thus, the actual costs for cofiring and reburning will depend heavily on future prices of gas, the type of boiler, site-specific conditions including remaining boiler life, and technical advances in these SO_2 and NO_x reduction technologies. Nonetheless, cofiring and reburning today appear to offer low to moderate cost methods to accomplish some reductions of SO_2 and/or NO_x.

Summary

Cofiring gas has been shown to be effective as a means of reducing baseline emissions and for shaving the peak emissions of SO_2. Evaluation of the potential boiler operational benefits, such as reduced maintenance or boiler

parts life extension, will require long-term tests to measure these more subtle impacts.

Further, results will vary depending on degree of gas substitution, boiler type and design, coal and ash characteristics, and the primary reason for cofiring, e.g., slag reduction as opposed to SO_2 reduction. DOE is planning to participate in a program with SIGECo and ALCOA at Warrick County, Indiana, to help resolve some of these uncertainties.

Gas reburning, gas reburning with sorbent injection, and coal reburning to reduce NO_x are being investigated by DOE and others in several R&D and CCT projects. Results from these projects will provide a significant body of information on reburning technology and economics.

As a technique for boiler performance improvement, gas cofiring must be evaluated for each site-specific case where it is being considered. For emission control, gas cofiring is a low capital cost technique for achieving minor emission reductions. At current gas prices and at price levels projected by the Energy Information Administration in the near future, cofiring with gas can offer a competitive compliance strategy for emission reductions. If gas prices are higher than currently projected, it could affect the attractiveness of cofiring as an emission reduction technique unless there are offsetting boiler performance improvements.

Gas reburning represents a low capital cost approach to obtaining moderate NO_x reduction. The competitiveness of gas reburning, in terms of life cycle costs, could be somewhat higher than selective catalytic reduction (SCR), depending on future prices of gas and advances in the SCR technology.

Cofiring and reburning are two technologies which can be used to control SO_2 and NO_x in existing powerplants. Under proposed acid rain legislation, these two technologies offer alternatives for utilities to consider when, in the future, utilities likely will be faced with an emissions cap. These technologies in combination with others, will allow utilities flexibility in seeking least cost methods to comply, on a system-wide or regional basis, with new emission regulations to control precursors of acid rain.

DOE Comments on S.1848

As you can see, a significant effort on cofiring and reburning is underway and future work is planned. Cofiring, for the most part, is a mature technology that has relatively low technological risk. Current projects should provide a sufficient basis for the utility industry to decide whether to adopt cofiring as an emission reduction strategy. Reburning is currently in the demonstration phase and is also receiving federal support through both the DOE R&D and Clean Coal Technology programs. The additional funding provided in S. 1848 must be weighed against budgetary priorities and the fact that the projects it would finance would likely duplicate many ongoing efforts. The Department, therefore, must oppose this legislation.

The Department supports the increased use of natural gas as an important part of both its national energy and environmental policies. Natural gas has beneficial environmental qualities and it is in the national interest to encourage cofiring gas and coal. However, the challenge to greater use of natural gas is not so much a technological challenge as it is a regulatory and infrastructure challenge. Significant steps have been taken to remove the regulatory burdens at the wellhead, through enactment of price decontrol legislation. Congress has also repealed most of the Powerplant and Industrial Fuel Use Act, thus opening up new opportunities for gas marketing. But questions remain regarding present pipeline capacity, the best way to resolve problems in the certification process, and the possibility of making adjustments to give the Nation's natural gas system greater flexibility to respond in times of emergencies. DOE has begun addressing these questions in a joint Deliverability Study with the Federal Energy Regulatory Commission.

Consequently, while we embrace the concept of cofiring, S. 1848 seems unnecessary in light of current government and industry activities and the need to focus attention more on resolving questions concerning distribution and deliverability of natural gas.

Thank you for allowing me the opportunity to comment on these issues. I will be glad to answer any questions you may have.

Senator FORD. Thank you.
Mr. Webb.

STATEMENT OF DAVID O. WEBB, SENIOR VICE PRESIDENT, POLICY AND REGULATORY AFFAIRS, GAS RESEARCH INSTITUTE

Mr. WEBB. Thank you, Mr. Chairman.

I appreciate the opportunity to appear before you today to present GRI's testimony on S. 1848, the Natural Gas Cofiring Promotion Act of 1989.

GRI strongly endorses this legislation to create an R&D program in the Department of Energy to conduct field tests necessary to firmly establish by mid-1993 that cofiring natural gas and coal is one of the most cost-effective near-term methods of reducing SO_2 and NO_x emission from existing utility boilers.

GRI is an independent not-for-profit scientific research organization that plans, manages and finances a cooperative R&D program of approximately $180 million in 1990 for the benefits for its 314 members. Thanks to the initiatives of you, Senator Ford and Senator Bingaman, this legislation, if enacted, would provided critical Federal support to accelerate the demonstration of cofiring and reburning natural gas with coal.

Federal support is important, because its potentially low-cost, near-term retrofit option will not be used by the electric utility industry until optimum natural gas injection levels are conclusively demonstrated and documented, and the economics of the technology are firmly established for the three major boiler designs primarily used by utilities on several different types of coal.

Pending passage of amendments to the Clean Air Act make Federal support for coal firing even more critical, because the Phase I acid rain compliance deadlines in the legislation. For cofiring to make the largest contribution to help solve utility boiler emission compliance problems in Phase I, cofiring must be widely demonstrated—and I emphasize widely demonstrated—by mid-1993.

This Act gives DOE the mandate and the funding authority to establish 50/50 cofunding programs with industry for these demonstrations. GRI with DOE, as industry partners, is currently planning of conducting R&D at six utility sites on several cofiring and reburn technologies.

We are demonstrating two generic cofiring technologies. These are: basic cofiring, where coal is fired in the primary combustion—where gas is fired in the primary combustion zone with coal to trim SO_2 and NO_x. The only test we have where we have conclusive data to date is the Duquesne Light Company with consolidated natural gas, where we documented 25 percent reduction of NO_x emissions, using 6 percent to 10 percent natural gas and also in some instances, we got greater than proportional reductions of SO_2.

We are looking at gas reburning in which gas is combusted in a staged manner, creating a secondary combustion zone to achieve 50 percent to 60 percent NO_x emissions reductions, 15 percent to 20 percent SO_2. Gas reburn can be mated with other advanced technologies, including sorbent injection to achieve what we believe are greater reductions in SO_2, potentially up to 50 percent.

The best opportunity for gas reburning sorbent injection and reburn are projected to occur on medium to small-sized units typically less than 500 megawatts built in the 1950s and 1960s. The majority of these plants are primarily located in the States of Kentucky, Ohio, Illinois, Indiana, Pennsylvania and West Virginia. These States have 47 percent of the total installed boiler capacity.

From 1988 through 1984 GRI has spent or plans to spend approximately $25 million on R&D and cofiring and reburn technologies. GRI anticipates an additional $25 million in cofunding from Federal, State and industrial partners. Once it becomes a commercial-proven technology, many utilities could use cofiring and other technologies such as coal-washing to meet the proposed Phase I standards of 2.5 pounds of SO_2 per million Btu's.

Reburn is particularly attractive as an in-furnace NO_x reduction technique for cyclone boilers, because they are high NO_x emitters. Many of these plants are also located in the mid-West and are 20 years to 30 years old and, therefore, good candidates for this technology.

What is needed now is an accelerated DOE gas industry demonstration program to conduct reburning and cofiring tests over extended periods of times, up to 6 to 9 months duration to measure and document the cost in emissions reductions benefits.

GRI's three cofiring tests are beginning to produce significant data on the environmental advantages, but they are only for small limited short-term test. Additional long-term testing is required. These long-term tests should consider a variety of boiler designs, loads, coal properties, firing configurations and natural gas percentages. S. 1848 would make these tests possible.

The pending clean air legislation has resulted in a delay and perhaps the cancellation of rounds four and five of DOE's clean coal program, thus limiting resources for future cofiring test. Therefore, additional funding, as provided in 1848, is urgently needed.

Utility confidence can only be established by installing and demonstrating cofiring technologies on a succession of plants. To meet Phase I compliance deadline, cofiring technologies need to be demonstrated in long-term test by mid-1993. This deadline makes S. 1848 particularly timely. Top priority should be given to its enactment.

Also, we would encourage Congress to appropriate $9 million in the DOE fiscal year 1991 fossil energy budget to initiate joint DOE industry cofiring projects as soon as possible.

While prompt passage of S. 1848 and congressional funding for cofiring demonstrations for DOE are critical, one other significant barrier exists to widespread deployment of cofiring technologies. This barrier, as you mentioned in your opening statement, Mr. Chairman, is the increased regulatory uncertainty and risk created by EPA's WEPCO decision.

This uncertainty has already delayed the start of GRI and DOE's round one clean coal project in Illinois by about 8 months. Without extensive efforts by DOE, and particularly Jack Siegel here to resolve the issue with EPA, we would not even been able to have started this program.

This week, we were also informed by industry participants in the cofiring test plants in Indiana, that they had put on hold the Phase

II design and installation activities, pending resolution of the WEPCO problem. So it is not just a theoretical problem; it is a real problem and beginning to impact the demonstration of this technology.

I understand that another panel at this hearing will address the WEPCO issues, but I cannot overemphasize the importance of getting proper language in the clean air legislation to resolve this uncertainty. Language should clarify that no physical change, or change in the method of operation of a plant for the purposes of reducing emissions, shall be treated as a modification, if such a change does not increase the potential emissions of any air pollutant from the plant above the potential emissions prior to the change.

In conclusion, Mr. Chairman, natural gas, the cleanest burning fossil fuel, has a potential to make a significant contribution to reducing acid rain precursors, NO_x and SO_2, in both existing and utility power plants through cofiring. The passage of S. 1848 and the funding to carry out the provisions of legislation would assist tremendously in demonstrating this technology in time for it to be able to help utilities meet the mandates of the Phase I under the clean air amendments currently pending before Congress.

Without this congressional initiative, sufficient resources will not be available to demonstrate the long-term test of cofiring in more than one application for each of the major three types of boilers by mid-1993.

Thank you, Mr. Chairman. Again, I want to extend my appreciation for your efforts and Senator Bingaman's initiative in introducing this important legislation.

I will be glad to respond to any of the questions you or the Committee may have.

[The prepared statement of Mr. Webb follows:]

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TESTIMONY OF DAVID O. WEBB
SENIOR VICE PRESIDENT, POLICY AND REGULATORY AFFAIRS
GAS RESEARCH INSTITUTE
ON S. 1848, THE NATURAL GAS COFIRING
PROMOTION ACT OF 1989,
BEFORE THE SUBCOMMITTEE ON ENERGY RESEARCH AND DEVELOPMENT
COMMITTEE ON ENERGY AND NATURAL RESOURCES
MAY 8, 1990

INTRODUCTION

I appreciate the opportunity to appear before you today to present Gas Research Institute's (GRI) testimony on S. 1848, the Natural Gas Cofiring Promotion Act of 1989. GRI strongly endorses this legislation to create a research and demonstration program in the Department of Energy (DOE) to demonstrate and firmly establish that cofiring natural gas and coal is one of the most cost-effective near-term methods of reducing SO_2 and NO_x emissions from existing utility boilers.

GRI is an independent, not-for-profit scientific research organization that plans, manages, and finances a cooperative research and development (R&D) program ($183 million in 1990) for the benefit of its 314 members (gas distribution companies, producers, gas pipelines, municipals) and their customers. The R&D program is implemented through contracts with research organizations, engineering firms, universities, energy companies, and manufacturers. Approximately 10 percent of GRI's annual R&D budget is cofunded with the federal government, and an additional 10 percent of the annual research budget is coordinated with the federal government.

Due to the leadership and initiative of Senators Ford and Bingaman, the Natural Gas Cofiring Promotion Act of 1989 if enacted would provide critical federal support through DOE to accelerate the technology demonstration of cofiring and reburning natural gas with coal. Federal support is important because this potentially low-cost near-term retrofit technology--cofiring--will not be used by the electric utility industry until optimal natural gas injection levels for both environmental and operational benefits are conclusively demonstrated and documented and the economics of the technology are firmly established. The demonstrations must include the three major boiler designs (wall-fired, tangentially fired, and cyclone) on several different types of coal before the technology will become commercialized and widely used.

Pending passage of amendments to the Clean Air Act make federal support for cofiring even more critical because of the Phase I acid rain compliance deadlines in the legislation. For cofiring to make the largest contribution to help solve utility boiler emissions compliance problems in Phase I, cofiring must be widely demonstrated by mid-1993. The demonstration can be accomplished only by the dedicated joint effort of DOE and industry. The Natural Gas Cofiring Promotion Act gives DOE the mandate and funding authority to establish joint 50-50 cofunded programs with industry for these demonstrations.

Limited initial testing sponsored by GRI has clearly indicated cofiring has the potential to be a low-cost interim measure that would allow electric utilities with older power plants to continue to burn local medium- and high-sulfur coals while achieving emissions reductions in SO_2 and NO_x. Many utilities could use cofiring and other low-cost conventional technologies, such as coal washing, to meet the proposed Phase I standard of 2.5 pounds of SO_2/MMBtu. Without these low-capital-cost, near-term retrofit options (basic cofiring capital costs are $2-$5/kW), electric utilities could be left with no choices but to switch to higher-cost low-sulfur coals, phase out still useful older power plants, or make very large capital investments to install scrubbers. Any of these three options would significantly increase the cost of electricity.

Cofiring is particularly attractive for cyclone boilers because they are high NO_x emitters. They contribute about 21 percent of the NO_x emitted by pre-New Source Performance Standards (NSPS) coal-fired units even though cyclone-fired boilers represent only about 14 percent of the pre-NSPS coal-fired generating capacity. Many of these units are located in the Midwest and are 20 to 30 years old. Thus they are targeted for emissions reductions in Phase I. Cofiring technologies, particularly reburn, are uniquely well suited as an in-furnace NO_x reduction technique for cyclone-fired boilers.

What is needed now is an accelerated DOE/gas industry demonstration program to conduct cofiring tests over extended periods of time (up to six months) to measure and document the costs and emissions reduction benefits of cofiring. Over the past three years, GRI has spent approximately $14 million on R&D in cofiring technologies. In addition, GRI anticipates spending another $12 million on cofiring technologies by 1994. However, even though GRI is involved in six cofiring field tests (see Figure I attached), only two tests are planned on a cyclone boiler. Furthermore, the pending clean air legislation has resulted in a delay and perhaps in the cancellation of Rounds 4 and 5 of DOE's Clean Coal Program, thus limiting future cofiring tests. Therefore, additional funding should be used to test:

1. Additional wall- and tangentially fired units to provide data needed from more than one unit that will give utilities confidence in the technology and will allow vendors to develop performance guarantees.

2. Units having different internal dimensions and residence times.

3. Units burning different coals (especially to determine how cofiring can assist utilities in combusting low-sulfur coal).

4. Units operating under wet-bottom conditions.

S. 1848 is urgently needed to provide the funding necessary to conduct cofiring tests on cyclone boilers.

Utility executives need proven cost-effective options to meet the emissions standards of the proposed amendments to the Clean Air Act. User confidence can only be established by installing and demonstrating cofiring technologies on a succession of existing plants. To provide the widest range of options, cofiring technologies must be demonstrated in long-duration tests by 1993.

This deadline makes S. 1848 particularly timely; top priority should be given to its enactment. GRI believes passage of S. 1848 is sound national energy policy and hopes Congress will also appropriate $9 million in the DOE FY 1991 Fossil Energy budget to initiate joint DOE/industry cofiring projects as soon as possible.

While prompt passage of S. 1848 and Congressional funding of $9 million in FY 1991 for cofiring demonstration by DOE will resolve the technical barriers to the commercialization of cofiring, one other significant barrier exists to widespread deployment of cofiring technologies. This barrier is the increased regulatory uncertainty and risk created by EPA's WEPCO decision. Utility executives will be very reluctant to participate in cofiring demonstrations or to deploy the technology if they believe participation will expose their utilities to New Source Performance Standards or will prevent the application of significant deterioration reviews. This uncertainty has already delayed the start of GRI and DOE's Round I Clean Coal project in Illinois by about eight months. Also, GRI was recently informed by industry participants in the cofiring test planned in Indiana that Phase II design and installation activities are being placed on hold pending resolution of the WEPCO problem.

I understand that another panel at this hearing will address the WEPCO issue, but I cannot overemphasize the importance of getting proper language in the clean air legislation to resolve this regulatory uncertainty. Language should clarify that no physical change or change in the method of operation of a plant for the purposes of reducing emissions shall be treated as a modification if such change does not increase the potential emissions of any air pollutant from the plant above the potential emissions prior to the change.

GRI'S GAS COFIRING R&D PROGRAM

GRI, with industry participation, is currently conducting R&D on several cofiring technologies that utilize the clean burning characteristics of gas to mitigate environmental problems that are produced by burning coal in boilers. As part of this effort, GRI is also participating in field tests of three advanced clean coal cofiring technologies through DOE's Clean Coal Technology program. Continued development of these technologies is not only of interest to the gas industry specifically but also represents good energy policy for the nation.

GRI's research on emission control technology is guided primarily by the recognition that natural gas can be combusted with coal as one cost-effective approach for existing coal-fired boilers to meet present and anticipated clean air regulations. Research includes significant efforts to optimize the use of gas with coal to help reduce NO_x and SO_2 emissions from fossil-fuel-fired utility and industrial boilers. Major attention is currently directed at the near-term option of testing cofiring techniques.

Two core gas cofiring technologies are under development. These are:

1. Basic Cofiring. Gas is concurrently fired in the primary combustion zone with other fuels to trim SO_2, NO_x, and particulate emissions.

2. Gas Reburn. Gas is combusted in a staged manner creating a secondary combustion zone to achieve 50 to 60 percent NO_x emission reductions and 15 to 20 percent SO_2 reductions. Gas reburn can be mated with other technologies including sorbent injection and low-NO_x burners to achieve even greater reductions in SO_2 or NO_x.

In addition to emissions control, gas cofiring may simultaneously help provide solutions to a range of boiler operational problems. These potential operational benefits include mitigation of capacity derating problems (helping older plants operate at or near their rated design), improved unit availability, improved load following, increased coal vendor flexibility (widening the range of coals that can be burned), slagging/fouling control, and other benefits that can be of economic value to utilities. Understandably, boiler operational benefits and the associated value of these benefits are highly site specific. Nevertheless, opportunities potentially exist for the incremental cost of gas to be significantly offset by the value of operational benefits alone.

In 1988, 1989, and 1990, GRI will spend approximately $13.6 million on R&D in cofiring technologies. For 1991 through 1994, GRI plans to spend approximately $12 million to further the R&D (see Table I). GRI anticipates matching the $12 million with additional $24.9 million in cofunding from federal, state, and industrial partners.

TABLE I
GRI Cofiring Budget
($ Millions)

	Funding 1990 & Prior Years		Funding 1991-1994	
Technology	GRI	Other	GRI	Other
Cofiring/Utility	$ 2.0	$ 3.1	$ 0.3	$ 0.0
Reburn	2.6	4.8	6.2	18.5
Reburn/Sorbent Injection	9.0	17.4	4.5	4.0
Cofiring/Industrial	0.0	0.0	0.6	2.4
Totals	$13.6	$25.3	$11.6	$24.9

Basic Cofiring

As an example of cofiring R&D and its potential contribution to reducing emissions, Duquesne Light Co., Consolidated Natural Gas Co., and GRI in 1987 completed a basic cofiring field study at Duquesne's Cheswick Power Plant on a tangential boiler near Pittsburgh. The field test documented a 25 percent reduction of NO_x emissions using 6 to 10 percent natural gas cofiring with local coal. The test also documented greater than proportional reductions of both NO_x and SO_2 emissions under certain operating conditions. The test also explored other advantages of cofiring, including cleaner and faster start-up, reduced slagging, and the ability to fire lower quality coal.

A second basic cofiring evaluation has recently been initiated on two wall-fired boilers in southern Indiana belonging to the Alcoa Aluminum Company and Southern Indiana Gas and Electric Company. Objectives of this field study include evaluations of basic cofiring's ability to trim SO_2 emissions, mitigate slagging problems, and provide increased capacity and availability. Radian Corporation, Energy Technology Consultants, and Sargent and Lundy are conducting the field evaluation. Funding for the study is being provided by Alcoa, Southern Indiana Gas and Electric, DOE, gas utilities servicing the station, and GRI. Phase I diagnostic testing at the Warrick Station is completed. Based on Phase I economic calculations performed by Alcoa, it is feasible to proceed with system installation. However, Phase II design and installation activities have been placed on "hold" due to regulatory uncertainties arising from EPA's WEPCO decision.

Another basic cofiring field evaluation was conducted on a tangential boiler in Oklahoma belonging to Public Service of Oklahoma (PSO). Funding for this study was provided by PSO, APTECH Engineering Services, Inc., and GRI. APTECH and Energy and Environmental Research Corporation (EERC) conducted the field study. With 10 percent cofiring, stack opacity was reduced by 30 percent, and SO_2 emission was lowered 15 percent. NO_x levels were unaffected by 10 percent cofiring. Preliminary data suggest that cofiring has the potential to increase tube life by reducing high temperature creep rates. Test data was inconclusive regarding the effect of cofiring on slagging and fouling. Nevertheless, no significant detrimental effects of cofiring 10 percent gas were observed.

GRI's three cofiring tests are beginning to produce significant data on the environmental advantages of combustion of coal and small quantities of gas (nominally 10 percent) in the same boiler. However, due to funding limitations, these are short-term tests. Additional longer-term testing is required to better quantify emissions and operational effects. These long-term tests should consider a variety of boiler designs, loads, coal properties, firing configurations and natural gas percentages. S. 1848 would make these tests possible.

Cofiring has the potential to be a low-cost interim means for electric utilities with older power plants to continue burning local high-sulfur coals and also to achieve emissions reductions. Without cofiring or a similar low-cost near-term retrofit option, electric utilities could be left with no choice but to switch coals, phase out still useful older power plants, or make exceptionally large capital investments in retrofitting such plants with scrubbers. Confirmation of the advantages of cofiring gives electric utilities the option to continue to use their existing coal supplier by burning 10 to 15 percent natural gas with coal, but any of the other options would significantly increase the cost of electricity.

Reburn

While basic cofiring offers utilities low cost emissions trim and operational benefits, gas reburn promises to achieve even greater emissions reduction at slightly higher capital cost. (Gas reburn capital costs are $15-$30/kW.) The technology is applicable to all three primary utility boiler designs. The term "gas reburn" refers to the injection of natural gas into the upper boiler

region of a boiler to produce a fuel-rich zone that reduces NO_x emissions. Overfire air is added in a final burnout zone to complete the overall combustion process. In this reburn zone, much of the NO_x present (50 to 60 percent or more) is converted to elemental nitrogen. Pilot tests indicate that a majority of cyclone boilers could successfully apply this technology to reduce their NO_x emissions. Pilot scale tests indicate that 20 percent natural gas cofiring in a reburn application can reduce NO_x emissions by 60 percent and SO_2 emissions by 20 percent. When mated with sorbent injection technology to increase SO_2 capture, gas reburn has the potential to achieve a 50 percent reduction in SO_2 emissions in addition to 60 percent NO_x emissions reduction. If these laboratory results can be duplicated in upcoming field tests, then the role of natural gas as a cost-effective option for reducing acid rain emissions will become a reality. This is the objective of GRI's gas cofiring/reburn R&D program.

Reburning is uniquely well suited as an in-furnace NO_x reduction technique for cyclone-fired boilers, which produce significantly more NO_x than wall-fired or tangentially fired boilers. Cyclone-fired boilers contribute about 21 percent of the NO_x emitted by pre-New Source Performance Standards (NSPS) coal-fired units even though cyclone-fired boilers represent about 14 percent of the pre-NSPS coal-fired generating capacity. Since the cyclone combustor cannot tolerate significant changes in its operation without the possibility of creating other problems, the cyclone combustor is limited to an in-furnace NO_x reduction technology. The only operation change required with reburn is that the primary fuel-feed rate be reduced in the primary combustor with an equivalent amount (on Btu basis) of fuel injected in the reburn zone, usually not more than 20 percent of the total fuel input. The excess air, and therefore the air/fuel stoichiometry within the cyclone, can be held constant, thereby lessening the potential for cyclone operational problems. Based on past research, the conservative expectation is that NO_x will be reduced in a cyclone-fired boiler by at least 50 to 60 percent.

A reburn project currently in progress is located at the Ohio Edison's 108 MW cyclone boiler at the Niles Power Plant to demonstrate reburn technology. Combustion Engineering is the prime contractor. The cost is estimated to be $10.6 million. GRI, the Electric Power Research Institute, Consolidated Natural Gas/East Ohio Gas, the Environmental Protection Agency, the Ohio Coal Development Office, Ohio Edison, Combustion Engineering, and DOE are cofunding the project.

The system design and fabrication phases of the Niles plant project have been completed. Plans are to install the reburn system during the regular boiler maintenance outage scheduled for May 1990. Baseline tests and parametric tests of the reburn system will follow the installation of the system for approximately six to nine months. The six-month performance test is scheduled to start in the spring of 1991. The project will be completed in April 1992.

A second reburn project, "Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler," is being conducted within the Clean Coal Technology Program. This will be a 50-50 cost-shared venture with a total estimated cost of $14.5 million. The project will be located at Public Service Company of Colorado's (PSCo) Cherokee Station Unit 3 in Denver.

This project will demonstrate the combination of gas reburning and low-NO_x burners on a 172 MW wall-fired utility boiler. It is believed that gas reburn

may enhance the emissions control performance of low-NO_x burners, thereby resulting in greater NO_x reductions. Prior to startup, PSCo will evaluate plans to install a sorbent injection system to be fully operational during the field evaluation. If a sorbent injection system is installed, the test will provide a unique opportunity to evaluate the integration of three advanced emission control technologies: gas reburning, low-NO_x burners, and sorbent injection.

The project will be conducted in three phases. In the initial phase, Energy and Environmental Research Corporation's (EERC) design methodology will be used to design the equipment and prepare the plans to complete the testing. A baseline test will be conducted. In Phase 2, the gas reburning and low-NO_x burners will be installed on the unit. Phase III is a comprehensive assessment of the performance of the combined emission control technologies in commercial service. Phase III includes three months of optimization tests followed by 12 months of operation by the utility operators in normal commercial service. A comprehensive series of emissions, boiler performance, and durability measurements will be made to establish a data base for subsequent commercial applications.

Cofunding for this project will be provided by EERC and PSCo, as well as GRI, the Electric Power Research Institute, Colorado Interstate Gas Company, and DOE. The project is scheduled to commence in late 1990, and the field evaluation will be completed in November 1993.

In a third reburn project, GRI is currently cofunding a gas reburn-sorbent injection (GR-SI) field test under Round I of the Clean Coal Technology program. The objective is to demonstrate gas reburning-sorbent injection at two utilities in Illinois. This project is being conducted by EERC.

The estimated total cost of the program to demonstrate GR-SI is $30 million over three to four years. GRI is providing $10 million, EERC is providing $2.5 million, and the Department of Energy and Natural Resources of the State of Illinois is cofunding $5 million. DOE, through the Clean Coal Technology program, is providing $15 million.

Two host sites have been selected: one at the Hennepin Station of Illinois Power and the other at Lakeside Station belonging to the City of Springfield's City Water, Light and Power Company. These sites will provide full-scale, operational data on a tangential coal-fired boiler and a cyclone coal-fired boiler, which are typical of pre-NSPS designs and comprise over half of the U.S. coal-fired generating capacity. These types of units produce 12 million tons of SO_2 per year. Plans are being considered for testing other coals. Each host site will be tested for a range of conditions culminating in a one-year long-term evaluation.

Like most electric utility technologies, applications of gas reburn and reburn combined with sorbent injection have to be assessed on a site-specific basis. Nevertheless, the best opportunities for applying GR-SI are projected to occur on medium- to smaller-size units (less than 500 MWs) typically built in the 1950s and 1960s. Therefore, the primary major market for GR-SI is in the Eastern and Midwestern coal-producing states: Kentucky, Pennsylvania, West Virginia, Ohio, Illinois, and Indiana. These states have 47 percent of the total installed boiler capacity, or a little over 88,000 MW. GR-SI represents a technology that provides utilities with a cost-effective means of

reducing SO_2 and NO_x emissions by retrofitting and operating older existing units until these older units are replaced with new generating capacity. GR-SI is one environmentally acceptable solution for older power plants burning high-sulfur coal.

NATURAL GAS RESOURCE BASE

Through cofiring and reburn technologies, natural gas can play a significant role in helping the nation use its vast coal supply in an environmentally acceptable manner. Natural gas is our nation's cleanest burning fossil fuel. Its combustion emits virtually no particulates, sulfur oxides, or reactive hydrocarbons and produces far lower emissions of carbon dioxide per unit of energy than coal or oil. Used selectively with coal, relatively small quantities of natural gas could contribute significantly to protecting our air quality at an extremely low capital cost. Given the size of the gas resource base and the economics of gas production, the competitive position of gas relative to other environmental control options should remain favorable. In addition, a million-mile pipeline and distribution network are already in place. Thus cost-effective solutions to using coal cleanly are both possible and practical by selectively cofiring with natural gas.

Despite assurances, many utility executives are concerned about the long-term availability of natural gas to meet the incremental demand that would be created by the large-scale adoption of gas cofiring and reburn technologies to meet new clean air requirements. The question of natural gas availability (how much at what price), is not exclusively a matter of geology.

The price and quantities of delivered gas will depend upon two principal factors:

1. The geology that ultimately makes the resource available and dictates part of the price, and

2. A flow of investment into the exploration, production, and transportation of gas to the user.

It has been determined in the GRI 1989 Baseline Projection of U.S. Energy Supply and Demand to 2010 that adequate sources of gas will be available to meet the additional demand for natural gas if natural gas is used widely for emissions control purposes. In economic competition based on coal and gas prices, indications suggest that actual market penetration of gas used for emissions reduction would range somewhere between 250 Bcf and 850 Bcf. Estimated consumption of natural gas in 1989 was 18.7 Tcf. Therefore, we are projecting an incremental demand of less than 5 percent of current consumption.

The claims that domestic gas production can be increased at competitive costs is supported by a recent DOE study An Assessment of the Natural Gas Resource Base of the United States (May 1988) that shows a technically recoverable reserve and resource base of 1,059 Tcf of natural gas exists in the Lower 48 states (See Table II). This resource base is made up of proved reserves, inferred reserves, and resources. The recovery of gas in the resources category requires discovery and development of new technology, some using improved understanding of reservoir geometry. Of that, 800 Tcf exists or is

estimated to exist in conventional reservoirs. More than half of the total resource evaluated in the Lower-48 states, or 583 Tcf of gas, is judged economically recoverable at less than $3/Mcf (wellhead prices, 1987$). An additional 174 Tcf of gas is judged economically recoverable in a price range of $3/Mcf to $5/Mcf.

TABLE II
Comparison of Recent Estimates of
U.S. Natural Gas Resources
(Tcf)

	DOE	PGC	GRI
Lower-48 Proven Reserves	159	154	159
Undiscovered Resources	900	678	978
Total Lower-48	1059	832	1127
Alaska	129	152	N/A
Total U.S.	1188	984	N/A

It is clear that there is no absolute resource limitation on increasing the annual production of natural gas for U.S. markets for the foreseeable future. If new applications such as cofiring or reburn were to enter the marketplace, they could be accommodated.

In summary, adequate economic opportunities exist to meet the projected growth in demand for gas, including emissions control market opportunities, at cost-competitive prices.

CONCLUSION

In addition to DOE's Clean Coal Technology demonstrations, it is obvious that other opportunities exist for the near-term development of cost-effective retrofit emission control technologies such as gas cofiring. GRI encourages the passage of S. 1848 to establish an R&D program to demonstrate cofiring and reburn for retrofit applications within the next three to four years since it is in the national interest to develop low-capital-cost retrofit options to reduce SO_2 and NO_x emissions from coal combustion.

Natural gas, the cleanest burning fossil fuel, has the potential to make a significant contribution to reducing acid rain precursors (NO_x, SO_2) in both existing and new utility power plants. The passage of S. 1848 and the authorization and appropriation of funding to carry out the provisions of this legislation would assist in conclusively demonstrating a technology that would be available in time to contribute to emission reductions expected to be mandated under the Clean Air Act Amendment currently under consideration in Congress. Without this Congressional initiative, sufficient resources will not be available to demonstrate cofiring technology on a long-term basis on each of the three primary boilers used by electric utilities.

Additional research is warranted to:

1. Determine the optimal natural gas injection levels for both environmental and operational benefits,

2. Ascertain applicability impacts to boilers not currently designed to fire gas,

3. Conduct longer-term testing to better quantify emissions and operational effects. These long-term tests should consider a variety of boiler designs, loads, coal properties, firing configurations, and natural gas percentages, and

4. Confirm the economics of cofiring.

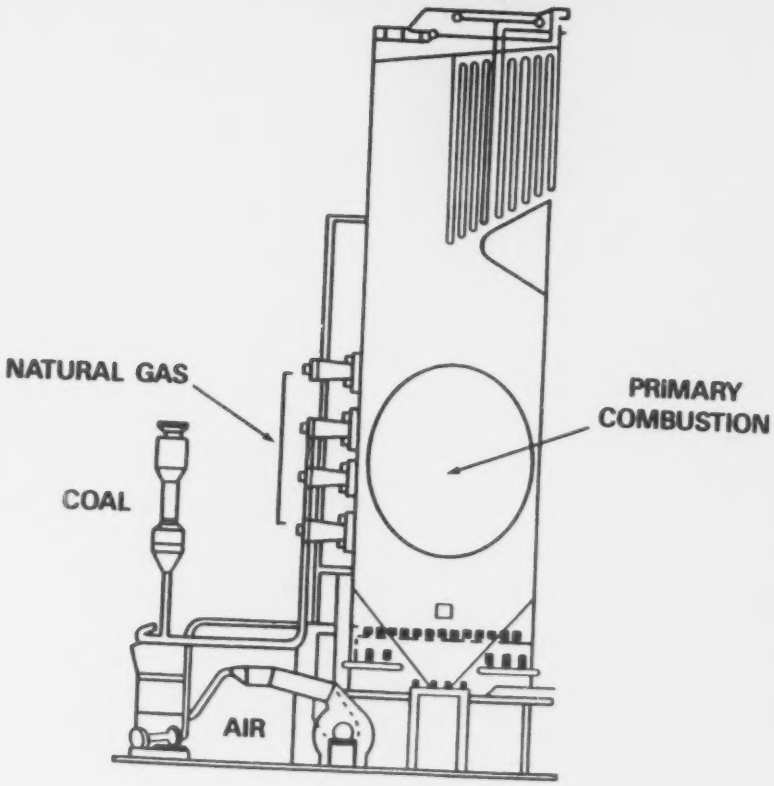
Thank you, Mr. Chairman. Again, I want to extend my appreciation for your efforts and initiative in introducing this important legislation. I will be glad to respond to any questions you or the Committee may have.

FIGURE I

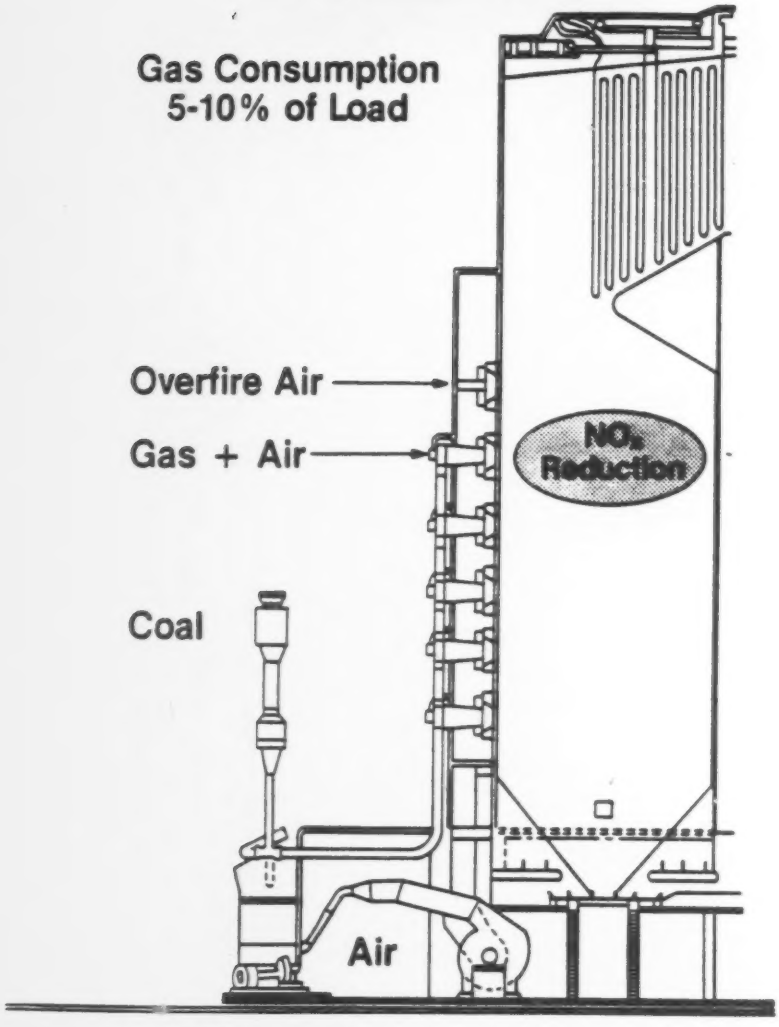
GRI COFIRING PROGRAM ACTIVITIES

Technology	Host Site	Cofunding - $ Million		Status
Basic Cofiring	1. Duquesne Light (Cheswick Station)	CNG	$ 0.6	Field evaluations completed. Two reports published.
		Duquesne Light	1.6	
		GRI	0.6	
			$ 2.8	
	2. Southern Indiana Gas & Electric and Alcoa (Warrick Station)	SIGECO	TBD	Diagnostic testing complete. Conceptual design for cofiring prepared.
		Alcoa	TBD	
		Gas Utility TBD	TBD	Economic feasibility study complete.
		U.S. DOE	TBD	Decision by host site to proceed to Phase II engineering design by 6/90.
		GRI	0.7	
			$	
	3. Public Service of Oklahoma (PSO) (Northeastern Station)	PSO	$ 0.5	Phase I short-term collection activities complete. Phase II long-term decision by 6/90. Data available summer of 1990.
		Aptech		
		GRI	0.3	
		Phase I	$ 0.8	
Gas Reburn	1. Ohio Edison (Niles Station)	U.S. EPA	$ 1.2	Phase I design activities complete. Phase II construction begun 3/90.
		EPRI	1.7	
		State of Ohio	1.0	Project completion expected 3rd quarter 1992.
		CNG/East Ohio Gas	1.2	Data collection starts 9/90.
		C.E.	0.4	
		Ohio Edison	0.9	
		GRI	1.7	
		U.S. DOE	2.5	
			$10.6	
	2. Public Service of Colorado (Cherokee Station)	U.S. DOE	$ 7.2	Selected 12/89 as Clean Coal II project.
		PSCo	3.0	Contracts to be negotiated by 8/90.
		CIG	0.3	Project will combine reburn with low-No_x burners.
		EPRI	0.2	43-month project.
		EERC	0.2	
		GRI	3.5	
			$14.5	
Gas Reburn/ Sorbent Injection	1. Illinois Power (Hennepin Station)	U.S. DOE	$15.0	Phase I design activities completed for both sites.
		State of Illinois	5.0	Phase II construction at Hennepin started 1/90. Data collection starts 1/91. Project completion expected 4th quarter 1992.
		EERC	2.5	
		GRI	10.0	
	2. Springfield City Water, Light & Power (Edgewater Station)		$32.5	Phase II construction at CWLP targeted to begin 6/90. Data collection starts 9/91.

GAS/COAL COFIRING

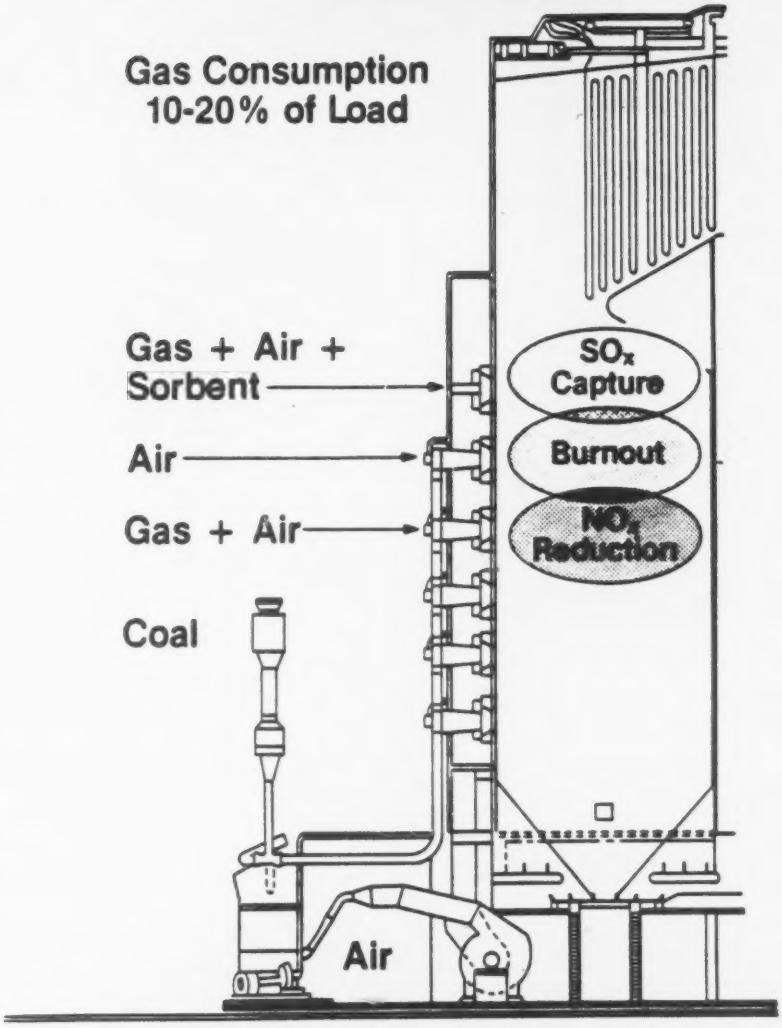


GAS APPLICATIONS RESEARCH



Gas Reburn – NO_x Control

GAS APPLICATIONS RESEARCH



Gas Enhanced Dry Sorbent Injection Plus Gas Reburn – SO_x/NO_x – Control

Senator FORD. Thank you, Mr. Webb.
Mr. Winberg.

STATEMENT OF STEVEN E. WINBERG, MANAGER OF COFIRING DEVELOPMENT, CONSOLIDATED NATURAL GAS SERVICE CO., ON BEHALF OF THE AMERICAN GAS ASSOCIATION AND THE INTERSTATE NATURAL GAS ASSOCIATION

Mr. WINBERG. Mr. Chairman, and members of the Subcommittee, my name is Steven Winberg, and I am the manager of cofiring development for Consolidated Natural Gas, one of the Nation's largest consolidated natural gas systems.

I appreciate your invitation to testify on S. 1848, the Natural Gas Cofiring Promotion Act of 1989. I am testifying on behalf of the American Gas Association and the Interstate Natural Gas Association of America. I particularly want to thank Senators Bingaman and Ford for their leadership on this important issue.

My company has a very strong interest in working in partnership with coal. Our service territory is in the heart of high sulfur coal country. If new clean air legislation devastates the high sulfur coal industry, as some have predicted, we will suffer also. That is why we believe developing cofiring is essential. We simply cannot allow a significant portion of our most abundant domestic energy resource to lie untapped.

S. 1848, with a very modest commitment of Federal resources would encourage and speed development of important new cofiring technologies that will allow midwestern utilities to comply with new clean air standards, while continuing to use domestic coal reserves.

C&G pioneered cofiring technology, and we have an active participation in several demonstration projects which are described more fully in my written testimony. Mr. Siegel and Mr. Webb have described the various coal firing technologies, so I will focus mainly on the economics of cofiring.

There is a joint AGA/INGAA report attached to my testimony which analyzes the economics of cofiring and the proximity of 50 major cofiring candidates to natural gas pipelines. But a simple comparison helps make the point. Cofiring costs anywhere from $2 to $100 per kilowatt to install, depending on whether basic cofiring, natural gas reburn or reburn with sorbent injection is chosen.

Scrubbers on the other hand cost $150 to $300 per kilowatt. Many utilities could take advantage of cofiring technologies in Phase I, as proposed by S. 1630. Also cofiring technologies, in conjunction with other conventional low-cost options, such as coal washing, could help most utilities meet the Phase I target while retaining their current coal supplier.

Therefore, cofiring should be of particular interest to midwestern utilities, because it is a viable, low-cost alternative to switching and scrubbing. Cofiring would also be a cost-effective solution for many utilities in meeting Phase II standards. C&G has completed detailed studies of the utilities in West Virginia, Ohio and Pennsylvania and concluded that for many of them, cofiring technology can be one part of a continuing SO_2 and NO_x compliance strategy.

Cofiring would also be attractive to the so-called clean plants. They will face both NO_x reduction requirements and limits on their SO_2 allowances. Cofiring would help them meet their NO_x reduction obligation, and at the same time provide an emissions trim option that could help them meet their SO_2 limits or perhaps generate growth allowances.

Most federally supported cofiring demonstrations have focused on reburn technology, because it is the only cost-effective NO_x control strategy for cyclone boilers. These boilers represent a significant number of high sulfur coal burning boilers, and they are inherently high NO_x emitters. However, due to a lack of Federal support, other very promising cofiring technology demonstrations have been of short duration and consequently have not produced the data needed to persuade utilities to incorporate cofiring into their compliance strategies.

What remains, then, is for DOE to take a larger role in assisting the development of cofiring technology. That is why S. 1848 is so important. The bill would give DOE the authority and obligation to expand existing research and initiate new projects. As results flow from more demonstration projects, DOE can provide invaluable assistance in compiling, analyzing and publicizing the data.

AGA and INGAA believe that passage of S. 1848 would send an important signal to electric utilities that cofiring is a promising emissions control option, and that DOE will be actively pursuing its development. However, if S. 1848 is to accomplish its objectives the WEPCO issue must be appropriately resolved.

There is another panel focusing on WEPCO, and you have heard about it twice already. But I do want to stress that AGA and INGAA fully concur with the testimony that will be offered in the second panel by Mr. Frank Blake. If the WEPCO issue is appropriately resolved, then, S. 1848 would promote production and use of domestic resources to help ensure national energy security and a cleaner environment.

We applaud and fully support the research and demonstration program that S. 1848 would establish. We believe that $9 million a year for 3 years, in addition to industry funding, will be money well spent.

Thank you, Mr. Chairman. That concludes my testimony. I will be happy to respond to any questions.

[The prepared statement of Mr. Winberg follows:]

TESTIMONY OF

STEVEN E. WINBERG

MANAGER OF COFIRING DEVELOPMENT

CONSOLIDATED NATURAL GAS COMPANY

ON BEHALF OF

THE AMERICAN GAS ASSOCIATION

AND

THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

BEFORE

THE SUBCOMMITTEE ON ENERGY RESEARCH AND DEVELOPMENT

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

ON S. 1848

THE NATURAL GAS COFIRING PROMOTION ACT OF 1989

MAY 8, 1990

INTRODUCTION

Mr. Chairman and members of the Subcommittee:

I am Steven Winberg, Manager of Cofiring Development, Consolidated Natural Gas Company, one the nation's largest integrated natural gas systems.

I am speaking on behalf of the American Gas Association (A.G.A.) and the Interstate Natural Gas Association of America (INGAA). A.G.A. is a national trade association comprised of some 250 natural gas distribution and transmission companies serving over 166 million natural gas consumers throughout the United States. INGAA is a national trade association representing the interstate natural gas pipelines of the United States and the inter-provincial pipelines of Canada.

I appreciate this opportunity to appear before your Subcommittee in support of S. 1848, The Natural Gas Cofiring Promotion Act of 1989. I want to commend Senators Ford and Bingaman for their sponsorship of S. 1848 and their leadership on the issue of cofiring. Their foresight in this area will help natural gas play a role in clean air compliance strategy, energy security and utility operations improvement by fostering the development and growth of cofiring technologies. My comments focus on the various cofiring options, the research and development work now underway, and how natural gas can be used in partnership

with coal to promote sound environmental, economic and energy security goals.

Overview of Cofiring Technologies

Cofiring is the term commonly used to describe a family of technologies that involve the combined use of coal and a small percentage of natural gas.

Basic cofiring, where up to 10 percent gas is simultaneously burned with coal, is commercially available today and can achieve at least one-to-one SO_2 reductions and up to 25 percent NO_x reductions, along with a host of operational improvements. A second cofiring technique is called natural gas "reburn." The gas "reburn" technology uses gas to form a second combustion zone higher in the boiler, yielding NO_x reductions of 50 percent or more. A third variation of cofiring combines reburn with the injection of a sorbent, hydrated lime, to achieve greater SO_2 reductions. When reburn technology is mated with sorbent injection, SO_2 reductions of 70 percent are expected, while still achieving 50 percent NO_x reductions.

These latter two technologies have received demonstration grants under the clean coal technology program and tests on commercial boilers will begin soon. In addition, they are especially advantageous when applied to cyclone boilers because other conventional NO_x reduction techniques, such as low NO_x burners, cannot be used by cyclone boilers.

More advanced cofiring technologies, known as the Parsons process and the NOXSO process, offer the promise of even better results. These technologies are in the research and development stage.

Let me now describe these technologies in greater detail and elaborate on the benefits that cofiring can yield for utilities.

Basic Cofiring

Basic cofiring of coal with natural gas involves the injection of gas into a boiler to provide a fraction of its total heat input. Attachment A illustrates basic cofiring. Attachments A through C were prepared by the Gas Research Institute. Originally, it was thought that this technique would reduce the amount of SO_2 emissions in the same proportion of gas used in the boiler. However, a recent field evaluation at the Duquesne Light and Power Cheswick Station in Pennsylvania found that greater than proportional reductions of SO_2 occurred. That test, which involved a 570 MW tangentially-fired boiler, found that cofiring with one to three percent gas obtained SO_2 reductions of approximately three to ten percent. Six to 12 percent gas cofiring reduced NO_x emissions by ten to 25 percent.

This test also demonstrated that cofiring yields many other positive operational and environmental benefits in addition to the SO_2 and NO_x emissions reductions. These benefits include a reduction of particulate matter,

improvement of fly-ash quality, start-up improvement (if gas was not previously used), availability improvement, reduction in slagging, operation and maintenance cost reductions, peaking capacity increases, turn-down capability improvement, and boiler efficiency improvement.

A recent 24-day gas cofiring field test in Oklahoma also yielded positive results. Sponsored by the Gas Research Institute, this test on a ten year old multi-fuel capable, tangentially-fired 450 MW boiler, demonstrated that using ten percent cofiring yielded a 30 percent reduction in opacity and a 15 percent reduction in SO_2 emissions.

Our experience with basic cofiring has demonstrated that the results can vary between boiler types and that proper engineering of the modifications to the boiler is essential to maximize the benefits of cofiring. I mention this because there has been at least one report of a less successful cofiring experience, although that was a project that did not involve either DOE funds or support from the Gas Research Institute, so we are not able to know fully the circumstances under which the test occurred or the exact results. We believe that basic cofiring will result in multiple benefits from fuel savings to operational improvements to emissions reductions. But more testing is needed to measure and document these improvements and their related economic benefits. That is one reason why S. 1848 is so timely and so important.

Natural Gas Reburn

Natural gas reburn technology is aimed primarily at reducing power plant NO_x emissions. It also uses natural gas as a small portion of the boiler fuel, but unlike basic cofiring, reburn technology involves injecting that fuel into a zone beyond the primary combustion zone to create a natural gas rich "reburn" zone. Over-fire air is added in a final burnout zone to complete the overall combustion process. In this reburn zone, much of the nitrogen in the NO_x present is converted back to molecular nitrogen, N_2, the form in which it naturally occurs in the atmosphere. For an illustration of natural gas reburn technology see Attachment B.

Cyclone boilers are inherently high NO_x emitters and were designed to burn high sulfur coal which makes them high SO_2 emitters. Pilot tests indicate that a majority of cyclone boilers could successfully apply natural gas reburn technology in order to reduce their NO_x emissions by approximately 60 percent. This is particularly significant as no other NO_x reduction techniques of comparable cost exist for these boilers. In fact, the only other NO_x reduction technique that could be applied to cyclone boilers is selective catalytic reduction (SCR). SCR is capital, operation and maintenance intensive and may be prohibitively expensive for older boilers with limited remaining life. Although the majority of cyclone units are 20-30 years old, utilities plan to operate many of them for at least an

additional 10-20 years. In addition, the majority of these units are in the Midwest, an area targeted by S. 1630, the Clean Air Act Amendments of 1990, for acid rain and ozone emissions control.

Two reburn projects are being pursued. DOE, GRI, EPRI, EPA, my own company, and Ohio Edison are involved in a project to demonstrate reburn technology on a 108 MW cyclone boiler in commercial operation. Work is underway at Ohio Edison's Niles facility. The installation of the reburn system will be completed in June and shakedown testing will begin in July. The system will then undergo extensive evaluation, with a six month performance test scheduled to start in the spring of 1991.

The second reburn project was awarded in the round III clean coal competition. This project will examine the potential for combining reburn technology in a wall-fired boiler in combination with low-No_x burners. The unit is a 172 MW boiler at the Public Service Company of Colorado's Cherokee Station. A sorbent injection system may also be installed prior to the test, allowing a unique opportunity to test the three systems in conjunction with one another. This project is scheduled to get underway late this year and be completed in November of 1993.

Natural Gas Reburn with Sorbent Injection

Gas reburn combined with dry sorbent injection (GR-SI) refers to combining reburn techniques with the injection of

dry calcium-based sorbent in the over-fire air area of the boiler to reduce SO_2 emissions. Combining gas reburn with sorbent injection avoids the cost and complexity of other types of sorbent injection technology, because it improves sorbent utilization, which reduces the amounts of sorbent required, which in turn, decreases the additional particulate burden on the plant's precipitator. Using a 15 to 20 percent proportion of natural gas in a GR-SI configuration is expected to achieve NO_x reductions of 50 percent or more and also reduce SO_2 emissions by 70 percent. Attachment C illustrates the GR-SI approach.

GR-SI is considered applicable to all boiler designs, is more easily retrofitted and far cheaper than scrubber technology, does not result in waste sludge, and may offer some site specific operational enhancements. The best opportunities for applying GR-SI are projected to occur on medium to smaller size units (less than 500 MW), units with shorter remaining economic lives, and will probably be used on moderate to low capacity factor units. Such units would typically have been built in the 1950s and 1960s.

The Department of Energy has awarded Round I Clean Coal Technology funds to a gas reburn/sorbent project being conducted by Energy and Environmental Research, a California consulting firm. The project will get underway this year at two Illinois sites to provide data using a tangential-fired boiler and a cyclone boiler. Each of these tests will

include evaluations using various types of coal and are expected to include a year-long evaluation.

Second Generation Cofiring Technologies

The Parsons process, sponsored by Consolidated Natural Gas, the Columbia Gas Company, Delmarva Power and the Ohio Coal Development Office is known as the "Parsons" process. A pilot demonstration project has demonstrated 97 percent SO_2 removal and 94 percent NO_x removal using approximately 20 percent natural gas. This process works with either low or high sulfur coal and results in no waste sludge.

The NOXSO process, which uses gas to regenerate a patented sorbent material, reportedly can achieve 97 percent SO_2 removal and 70 percent NO_x removal. A demonstration project using this technique was selected for support in the recent Round III clean coal solicitation. Scheduled for completion in 1992, design began in April for the experimental NOXSO pollution control facility at Ohio Edison's Toronto, Ohio plant.

These processes work with either low or high sulfur coal and, in contrast to scrubbers, simultaneously reduce both SO_2 and NO_x, leaving no waste sludge disposal problems. In fact, both processes result in a marketable sulfur by-product.

9

Economics of Cofiring

The economics of using a particular natural gas cofiring technology at any given plant depend on a variety of factors, including size, other technical options, age of the plant, capacity factors, the sulfur content of the coal used, and the availability and cost of gas. A.G.A. and INGAA have examined the practicality of supplying gas for cofiring at 50 of the largest SO_2 emitting power plants. The variables included were utility hookup costs and pipeline costs. If the two most expensive plants to hookup are excluded, the average cost per mile was about $310,000. About one-half of the plants are located ten miles or closer to a gas pipeline and only seven were more than 20 miles away. See Attachment D. Also, for 90 percent of the cases, the hookups could be constructed within nine months. Thus, not only is the cost of providing service minimal compared to scrubbers, it can be implemented in a relatively short time period.

The estimated capital costs of actually modifying the plant to accommodate cofiring range from $2-$4/kw for basic cofiring, $15-$30/kw for gas reburn, and $50-$100/kw for reburn combined with sorbent injection. By comparison, the typical capital cost of a scrubber is $150-300/kw.

The best use for cofiring technologies appear to be as a compliance strategy for the Clean Air Act Amendments of 1990 on older boilers, where the cost of alternatives,

such as installing scrubbers, would be prohibitively expensive. Most of these boilers are in the Midwest.

Many utilities could take advantage of cofiring technologies in Phase I of the acid rain reduction program proposed by S.1630, where utilities would be required to meet an interim reduction target based on a 2.5 lbs/mmBTUs SO_2 emission rate. Cofiring technologies, sometimes in conjunction with other conventional, available, low cost options, such as coal washing, could help most utilities meet that target. Utilities could then retain their current coal supplier and await the development of emerging clean coal technologies including the second generation cofiring technologies, before choosing a final Phase II control option.

Cofiring would be a cost effective solution for many utilities in meeting Phase II emission standards at their plants. My company has completed detailed studies of the utilities in part of our service territory - West Virginia, Ohio and Pennsylvania - and concluded that for many of these utilities, reburn technology can be one part of a continuing SO_2 and NO_x compliance strategy.

Cofiring would also be attractive to the so-called "clean" plants not faced with SO_2 reductions. These plants will face NO_x reduction requirements and limits on their SO_2 tonnage allowances. Cofiring would help these utilities meet their NO_x reduction obligation and also provide an

emission trim option that could help them meet their SO_2 limits or generate growth allowances.

One appealing aspect of cofiring as an emission control option is that cofiring, when combined with low-cost commercially available coal cleaning, would allow a utility to retain 80 to 90 percent of its current coal supply. This should be of particular interest to Midwestern utilities that may believe their only SO_2 reduction options are scrubbing or switching to low sulfur coal. Installation of scrubbers would be extremely expensive. Plants that scrub would no longer be candidates for clean coal technology as it becomes commercially available. Switching fuels, on the other hand, can also be expensive and will result in economic dislocations in high sulfur coal mining communities.

Cofiring is an alternative to switching and scrubbing. Basic cofiring offers many utilities a "bridge" across the reduction requirements in Phase I of the acid rain program while preserving their options for Phase II.

What remains is for the Department of Energy to take a larger role in assisting the development of this emerging technology. That is why S. 1848 is important. The $27,000,000 authorized by S. 1848 for cofiring research and development would greatly assist in bringing the advanced and second generation cofiring technologies to commercial availability. The bill would also give DOE the authority and obligation to expand existing research and initiate new

projects. As the results begin to flow from more demonstration projects, DOE can provide invaluable assistance in compiling, analyzing and publicizing the data.

Given that utilities are already beginning to examine alternative compliance strategies, A.G.A. and INGAA believe that passage of S.1848 would send an important signal to the utility community that cofiring is a promising emission control option and that DOE will be actively pursuing its development.

It is appropriate at this point to express the gas industry's concern about the possibility that utilities undertaking boiler modifications in order to comply with Clean Air Act requirements will trigger the "new source performance" (NSPS) or "prevention of significant deterioration" (PSD) provisions of current law.

In this regard, the gas industry is very concerned that utilities will be reluctant to choose cofiring if doing so exposes them to the potential of having new source standards or prevention of significant deterioration review applied to them. We know that several cofiring demonstration projects have been delayed for more than six months while awaiting assurance from EPA that they would not be subjected to NSPS or PSD review. This issue, known as the "WEPCo" problem, is being addressed by another panel at this hearing. A.G.A. and INGAA fully concur with the Frank Blake's testimony. In addition we want to add our thanks to the members of this Committee for their support on the WEPCo issue.

Conclusion

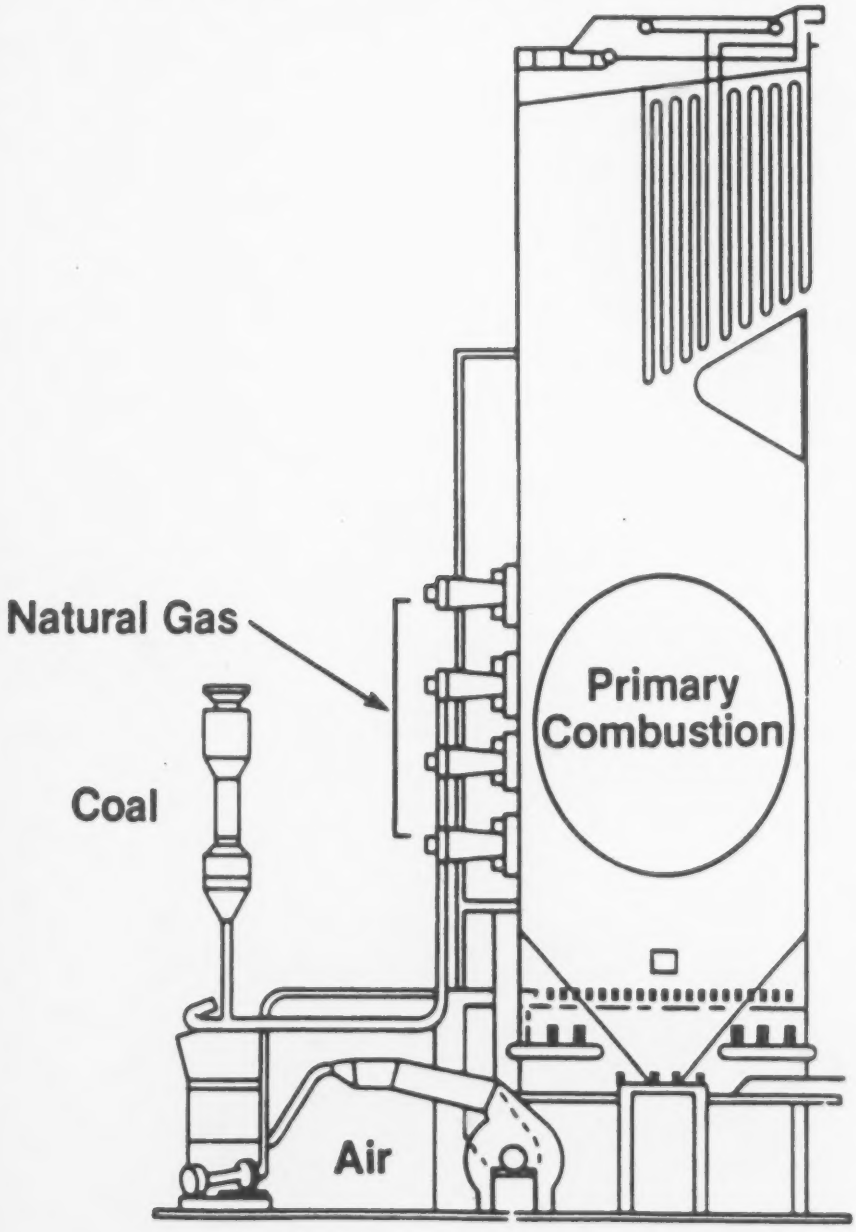
Historically, the Department of Energy has focused its efforts and resources on coal, nuclear, and conservation. Through the Department's National Energy Strategy development process, we are seeing an acknowledgement that natural gas has an important role to play in the nation's energy mix. Promoting the production and use of domestic resources to ensure national energy security and a cleaner environment makes sense.

The Natural Gas Cofiring Promotion Act of 1989 will help achieve this goal. It is in the national interest to develop and demonstrate technologies that can inexpensively and efficiently reduce SO_2 and NO_x emissions resulting from the combustion of coal. We applaud and fully support the research and demonstration program established by S.1848. We believe that nine million dollars a year for three years, in addition to industry funding, will be money that is well-spent to help ensure America's environmental health, economic strength and energy security.

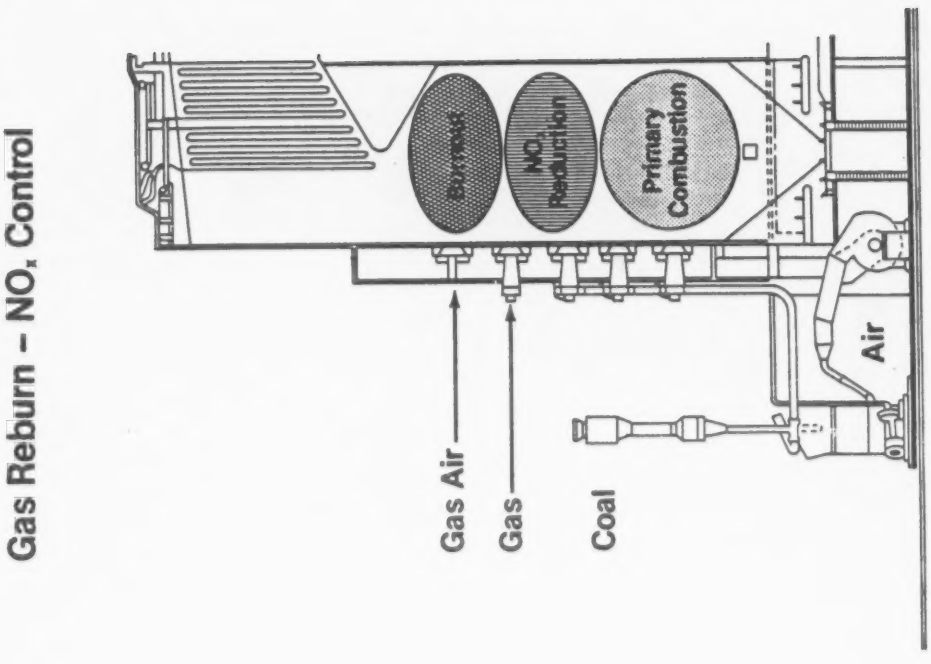
Thank you Mr. Chairman, that concludes my testimony. I will be happy to respond to any questions you or the members of the Subcommittee may have.

ATTACHMENT A

GAS/COAL COFIRING



ATTACHMENT B



ATTACHMENT C

Gas Reburn/Dry Sorbent Injection SO_x/NO_x Control

ATTACHMENT D

BACKGROUND REPORT

89-4
June 1989

CO-FIRING OF NATURAL GAS IN ELECTRIC POWER PLANTS: ARE PIPELINE HOOKUPS FEASIBLE?

EXECUTIVE SUMMARY

This report describes the methodology and results of a joint INGAA-AGA survey to determine the feasibility of providing natural gas services for co-firing at certain power plants. The survey covered interstate pipelines and local distribution companies operating in the vicinity of 50 of the largest power plants in terms of sulfur dioxide (SO_2) emissions. Co-firing of natural gas and coal has been proposed as an effective and economic strategy for lowering SO_2 and nitrogen oxides (NO_x) emissions from coal-fired boilers in power plants.

A total of 18 pipelines and nine local distribution companies responded to the survey, each providing data on one or more of the 50 plants. In some cases, as many as four companies provided information on serving one plant. The responses indicate that service to all 50 plants is possible. The average total cost per plant was $6.4 million, but is influenced by a few costly cases. If the two most expensive plants to hookup are excluded, the average cost was $4.1 million per plant. For the least expensive 48 plants to hookup, the average cost per mile was about $310,000. About half the plants were 10 miles or less from a gas system, and only seven were more than 20 miles away from one. For ninety percent of the cases, the hookups can be constructed within nine months.

PREFACE

A Background Report is an INGAA document which presents the results of research into a particular technical area of interest to those who wish a deeper understanding of the interstate natural gas industry. Background Reports are not aimed at in-depth discussion of policy issues. Rather, they summarize research intended to help illuminate some of the consequences of public policy initiatives. The information contained in this report was requested of INGAA and the American Gas Association (AGA) by the Office of Fossil Energy of the U.S. Department of Energy as part of its evaluation of possible options for the administration's position on new Clean Air Act reauthorization legislation.

This report was prepared by INGAA and is based on information collected by INGAA and AGA through a survey of their respective members. Any questions or comments should be directed to Samir Salama of INGAA (202/626-3200).

INTRODUCTION

In April, 1989, the Office of Fossil Energy of the U.S. Department of Energy asked INGAA and AGA to help its efforts to assess the feasibility of using natural gas co-firing as a means of reducing air emissions from electric utility power plants. The Office of Fossil Energy was seeking facts about:

- The feasibility of providing natural gas capacity by interstate pipelines and local distribution companies to serve the environmental needs of at least the top 50 sulfur dioxide-emitting power plants in the U.S.,
- The average cost of lateral hookups to deliver sufficient amounts of gas to these plants, and
- Environmental factors that might delay construction of the hookups beyond the normal nine-month pipeline construction cycle.

OVERVIEW OF THE TECHNOLOGY

Among the various methods to reduce sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emitted from electric utility generating plants, co-firing technologies are an option that holds great promise. Co-firing of natural gas with coal involves the concurrent burning of gas and coal in a boiler whereby gas provides a fraction of the boiler's total heat input.[1] There are three types of co-firing technologies applicable to coal-fired boilers:

- Basic co-firing: where 1 to 10 percent of the heat input to the boiler is supplied by gas introduced with coal in the primary combustion zone.
- Reburn co-firing: where 15 to 20 percent of the heat input is derived from gas introduced in a post-combustion zone to reduce SO_2 and NO_x emissions.
- Reburn with sorbent[2] injection (SI): where a sorbent is injected beyond the reburn zone primarily to reduce SO_2 emissions in addition to the NO_x reductions achieved by reburn alone.

The SI option is of special interest because it is being proposed as applicable to most boiler designs and is less expensive to install and operate than other options for flue gas desulfurization, including scrubbers. The best candidates for SI are expected to be units that are small to medium capacity (less than 500 MW), have remaining economic lives of ten to fifteen years and are operated at moderate to low capacity factors as cycling

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1 Recent experiments at the Cheswick power plant in Pennsylvania yielded reductions of SO_2 and NO_x emissions that are more than proportional to the amount of gas used.

2 A dry calcium-based material, such as calcitic hydrate, is used to capture sulfur oxides from flue gases as they approach the boiler stack.

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units. Typically, these units would have been built in the 1950's and 1960's.

Some of the important facts about gas use and its effect on emission in the three co-firing technologies are summarized here:

Option	Description	Emission Reduction	
		SO_2	NO_x
Basic co-firing	1%-10% gas, injected into the combustion zone	10%	25%
Reburn co-firing	15%-20% gas, injected above the main heat release zone	20%	60%
Reburn with sorbent injection	15%-20% gas, injected above the main heat release zone along with a sorbent	50%	60%

The capital costs of co-firing are far less than scrubber technology. Basic co-firing can involve costs as low as $2-$4/kW, typical reburn technology would cost an estimated $15-$30/kW, while reburn with sorbent injection is projected at $50-$100/kW.[3] This compares with capital costs of $300/kW or more for flue gas scrubbers. It has been reported[4] that even when O&M and fuel costs are considered, co-firing technologies remain more attractive than scrubbing under a wide range of assumptions.

Co-firing also provides other operational and environmental benefits. Some of these include: reduction of particulate emissions, improvement in fly-ash quality, start-up improvement, availability and boiler efficiency improvements, among others.

The costs of the gas hookups are only one consideration when evaluating co-firing as a means to comply with new emission standards. Electric utility companies and other operators of power plants have a number of options for complying with new emission standards proposed by various Clean Air Act reauthorization bills currently being debated in the U.S. Congress. These options include switching to lower sulfur coal, using flue gas desulfurization techniques (scrubbing), using clean coal technologies including co-firing, and shutting-down or reducing the utilization of the unit. The choice among these various options would be based on a number of factors specific to each plant or each unit within a plant, including relative equipment costs, operating and maintenance costs, fuel costs, plant or unit age, new regulations, feasibility of installing scrubbers and their environmental costs (gypsum storage and disposal).

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3 "Analysis of the National and Regional Potential for Gas Use in Electric Utility Emission Control," Gas Research Institute, 8600 West Bryn Mawr Avenue, Chicago, Illinois, 60631, p. 6.

4 *Ibid.*, p. 10.

METHODOLOGY

INGAA and AGA surveyed their members to determine the feasibility of providing gas services to a list of plants representing the nation's top 50 SO_2-emitting power plants (see Appendix A). This list, which also includes plant location, size and utility affiliation, was prepared by DOE's Office of Fossil Energy based on 1985 data. The Office estimated peak day gas requirements for each plant based on co-firing at the maximum rate of 20 percent of the total heat input to each plant.[5] The Office estimated total heat input to each plant conservatively from the plant's total nameplate capacity (in MW) by assuming 100 percent utilization (8,760 hours per year) and an industry average heat rate of 10,000 Btu/kWh. It was assumed that the maximum natural gas loads identified for each power plant would occur in the summer during the off-peak season for gas demand and that current natural gas deliverability at the wellhead would be sufficient to meet this incremental load.

The respondents were asked to identify plants that they could serve and, for each of these plants, provide the following information:

- Construction cost for the least cost route to the plant,[6]
- Distance of that route in miles of pipe,
- Balance-of-system costs[7] to supply that one plant if necessary, and
- Nonmonetary factors that might delay construction.

The respondents were asked also to quantify additional balance-of-system costs if all plants found feasible were to be added to the pipeline or distributor system.

The hookup cost data from both pipelines and distributors were compiled into one database and classified by plant. Balance-of-system costs due to the addition of individual plants were included in these costs. For each plant, the least cost hookup was selected as an initial possibility. If a selected least cost hookup was from a pipeline or distributor with balance-of-system costs for multiple hookups, then the initial cost was revised to include a prorated share of those costs. The pro rata share for each plant was calculated as the estimated balance-of-system costs divided by all plants included in those cost estimates.[8] The selection of the least cost routes was then finalized by

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5 To the extent that not all units within the 50 plants are coal-fired, this estimate of peak day requirement would be overstated.

6 For operational reasons, the delivery pressure for the plants was selected to be 50 psig (pounds per square inch gauge).

7 Costs incurred elsewhere on the system to provide this service, including possible upgrades of compressor stations, meters, valves, etc.

8 This proration is conservative because the balance-of-system costs might only be incurred if

repeating the selection process after taking into account the additional balance-of-system costs.

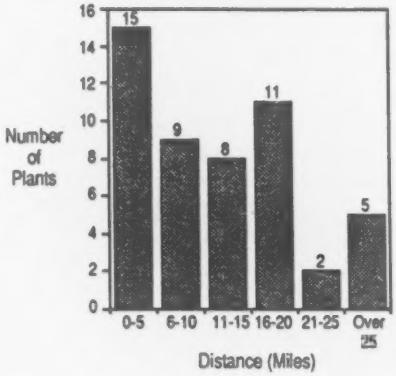
FINDINGS

Eighteen pipelines and nine distributors provided cost and distance data for one or more of the 50 power plants. In some cases, as many as five pipelines or distributors provided information on a hookup to one particular plant. Several survey respondents also indicated a willingness and ability to serve other, smaller electric power plants not on the top 50 list. The results discussed below represent data for the 50 plants only.

Distance

The mean distance between pipeline or distributor systems and the 50 plants is about 13 miles. A distribution of these distances is shown in Figure 1 and indicates that just under half of the 50 plants are within 10 miles of a pipeline or distributor. Seven of the 50 plants are more than 20 miles from a source of gas.

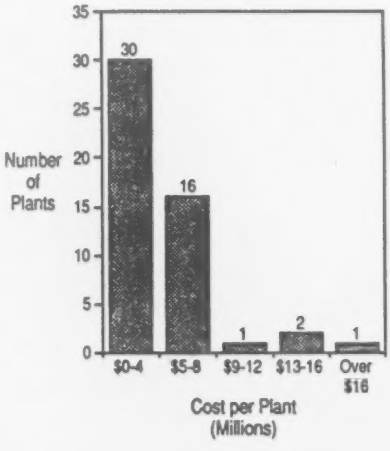
Figure 1
Frequency of Plants
Based on Distance



Hookup Costs

Construction costs to build a lateral hookup between a pipeline or distributor and the power plant ranged from $100,000 to $27 million. Figure 2 shows that 60 percent of the plants have construction costs which are $4 million or less. Of the 50 plants, 90 percent have hookup costs less than $8 million. The mean hookup cost is $4.4 million. However, if the five plants with the highest construction costs were excluded, the mean cost would drop to $3.1 million per plant.

Figure 2
Frequency of Plants
Based on Hookup Cost



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all multiple hookups were provided. For a subset of those hookups, the balance-of-system costs could be less.

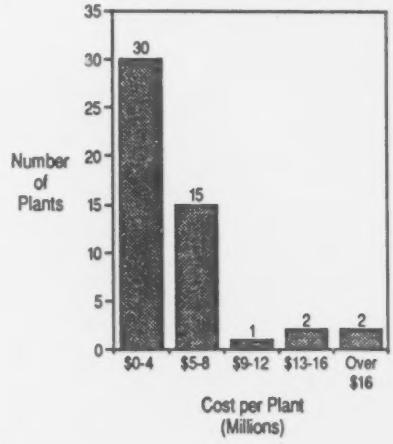
Balance-of-System Costs

Only 7 of the least cost routes to the 50 plants required additional system upgrade and resulted in balance-of-system costs. The balance-of-system costs were significant for two plants, which accounted for $92 million of the total $98 million in balance-of-system costs.

Total Costs

The total costs per plant include both the hookup and the balance-of-system costs. A distribution of the 50 plants based on total costs is shown in Figure 3. The mean total cost per plant for all plants is $6.4 million and the median is $3 million. Once again, the large costs of just a few plants skew the mean. If the two plants with costs over $16 million are removed from the sample, the mean total cost per plant falls to $4.1 million. On a cost per mile basis, the mean for the 50 plants is about $500,000. When the two most expensive plants are excluded, the mean total cost per mile is around $310,000.

Figure 3
Frequency of Plants
Based on Total Cost



Factors That May Delay Construction

Five plants had least cost hookup routes which involve factors that could delay construction. Three plants are located in densely populated areas which could delay the permitting process and hookups to two plants would require crossing a major river. These factors are likely to delay construction of hookups to only these five plants. The remaining 45 plants could be constructed in nine months or less.

CONCLUSIONS

Interstate natural gas pipeline companies and local distribution companies are capable of providing natural gas services to support co-firing at the nation's 50 highest SO_2-emitting power plants. Construction of these hookups can be completed quickly (within 9 months for most plants) and at moderate capital costs relative to other options. Further research would be needed to assess the feasibility and costs of gas hookups to serve co-firing needs of the next tier of 50 to 60 coal-fired power plants.

APPENDIX A

TOP 50 SULFUR DIOXIDE EMITTING POWER PLANTS

(Based on 1985 data)

Plant	Utility	State	County	Size (MW)	Gas Req'd. for 20% Co-firing (MMCF/D)
EC Gaston	Alabama Power Company	AL	Shelby	1880	90
Colbert	Tennessee Valley Authority	AL	Colbert	1350	65
Big Bend	Tampa Electric Company	FL	Hillsborough	1794	86
Crist	Gulf Power Company	FL	Escambia	1002	48
Wansley	Georgia Power Company	GA	Heard	1730	83
Harllee Branch	Georgia Power Company	GA	Putnam	1540	74
Yates	Georgia Power Company	GA	Cobb	1250	60
Bowen	Georgia Power Company	GA	Bartow	3160	152
Coffeen	Central Illinois Public Service	IL	Montgomery	913	44
Kincaid	Commonwealth Edison Company	IL	Cristian	1182	57
Baldwin	Illinois Power Company	IL	Randolph	1892	91
Joppa	Electric Energy Inc.	IL	Massac	1098	53
Gibson	Public Service Indiana	IN	Gibson	3340	160
Clifty Creek	Indiana Kentucky Electric Corp.	IN	Jefferson	1303	63
Cayuga	Public Service Indiana	IN	Vermillion	1070	51
Paradise	Tennessee Valley Authority	KY	Muhlenberg	2558	123
Ghent	Kentucky Utilities Company	KY	Carroll	2044	98
Braton Point	New England Power Company	MA	Bristol	1600	77
Monroe (MI)	Detroit Edison Company	MI	Monroe	3152	151
Montrose	Kansas City Power & Light	MO	Henry	494	24
New Madrid	Associated Electric Coop.	MO	New Madrid	1200	58
Labadie	Union Electric Company	MO	Franklin	2482	119
Thomas Hill	Associated Electric Coop.	MO	Randolph	1213	58
Roxboro	Carolina Power & Light Company	NC	Person	2558	123
Kyger Creek	Ohio Valley Electric Corp.	OH	Gallia	1086	52
Eastlake	Cleveland Electric Illum. Co.	OH	Lake	1257	60
Cardinal	Cardinal Operating Company	OH	Jefferson	1880	90
WH Sammis	Ohio Edison Company	OH	Jefferson	2304	111
Genl. JM Gavin	Ohio Power Company	OH	Gallia	2600	125
JM Stuart	Dayton Power & Light Company	OH	Adams	2441	117
Miami Fort	Cincinnati Gas & Electric Co.	OH	Hamilton	1292	62
Muskingum River	Ohio Power Company	OH	Morgan	1530	73
Conesville	Columbus & So. Ohio Electric	OH	Coshocton	1941	93
Conemaugh	Pennsylvania Electric Co.	PA	Indiana	1872	90
Montour	Pennsylvania Power & Light	PA	Montour	1647	79
Brunner Island	Pennsylvania Power & Light	PA	York	1558	75
Keystone	Pennsylvania Electric Co.	PA	Armstrong	1872	90
Hatsfields Ferry	Western Pennsylvania Power Co.	PA	Greene	1728	83
Homer City	Pennsylvania Electric Company	PA	Indiana	1970	95
Gallatin	Tennessee Valley Authority	TN	Sumner	1255	60
Johnsonville	Tennessee Valley Authority	TN	Humphreys	1485	71
Cumberland	Tennessee Valley Authority	TN	Stewart	2600	125
Centralia	Pacific Power & Light Company	WA	Thurston	1330	64
Oak Creek (WI)	Wisconsin Electric Power Co.	WI	Milwaukee	1552	74
Kammer	Ohio Power Company	WV	Marshall	712	34
Harrison	Monongahela Power Company	WV	Harrison	2052	98
Mount Storm	Virginia Electric & Power Co.	WV	Grant	1662	80
Mitchell (WV)	Ohio Power Company	WV	Marshall	1632	78
Amos	Appalachian Power Company	WV	Putnam	2933	141
Fort Martin	Monongahela Power Company	WV	Monongahela	1152	55

Senator FORD. Thank you, Mr. Winberg.

We have been joined by two of our members now.

Senator Burns, do you have an opening statement that you would like to make or comments?

Senator BURNS. I just have a statement, Mr. Chairman. Thank you very much. I think we have come to listen more than anything else. If I could just have it entered in the record, that will be fine with me.

[The prepared statement of Senator Burns follows:]

PREPARED STATEMENT OF HON. CONRAD BURNS, U.S. SENATOR FROM MONTANA

Mr. Chairman, I appreciate the opportunity to be here today to listen—and to learn—about the possibility of developing new technologies to cofire coal and natural gas.

In Montana, we have large supplies of both coal and natural gas. Any new technology to increase the consumption of either, or both, of these energy resources will be appreciated.

I am concerned about the WEPCO problem as it relates to the clean air bill and to this bill. We do not need to have the Environmental Protection Agency hamstringing projects that are designed to reduce air pollution. Instead, we need a Federal agency that is willing and ready to work hand in hand with the businesses of this Nation that are attempting to clean up the air around them.

Mr. Chairman, I will listen with interest to the presentations of the witnesses. Thank you.

Senator FORD. Senator Domenici.

STATEMENT OF HON. PETE V. DOMENICI, U.S. SENATOR FROM NEW MEXICO

Senator DOMENICI. Mr. Chairman, let me just say that it is a pleasure to be at a hearing where coal and natural gas are on the same side. I think that probably means that we have got something very significant going on.

Senator FORD. Suspect, huh?

[Laughter.]

Senator DOMENICI. But it seems to me that we ought to get on with encouraging this new technology. Obviously, we have to be in a position to do things differently these days, especially, since we want to comply with the Clean Air Act.

On the other hand, it is well understood that for some it is going to be very expensive. And if we can get where we ought to be for the consumers of this country at a more reasonable cost and yet do the clean-up, we ought to be on that side, and we ought to be on the side of getting there as fast as we can.

As far as the WEPCO decision, it is obvious that something has to be fixed. Because if the industry cannot find a way to be assured that what they are planning to do will indeed be permitted, and if some new source performance standards, as fragile as they are in the process of being promoted, it seems to me industry is doing exactly what one would expect and that is to back off. And we have to do something to encourage them to continue.

So I think the thrust is a good one. Even though some of the research is already occurring, I am hopeful that this will make it more obvious that Congress is on the side of proceeding and wants to provide additional incentives to the clean coal technologies and the money that is already being spent there.

And so I congratulate you on the hearing and thank my colleague, Senator Bingaman, for his leadership in this regard.

Senator FORD. Thank you, Senator.

Let me add to the record a statement by our chairman of the full committee, Senator Johnston. He is showing a strong continuing interest in resolving the WEPCO problem.

[The prepared statement of Senator Johnston follows:]

PREPARED STATEMENT OF HON. J. BENNETT JOHNSTON, U.S. SENATOR FROM LOUISIANA

Thank you, Senator Ford, for calling today's hearing on S. 1848, the "Natural Gas Cofiring Promotion Act." I congratulate you and Senator Bingaman on your sponsorship of this legislation.

I am particularly pleased that today's hearing includes a panel to address the so-called WEPCO issue. EPA's WEPCO policy is contrary to the thrust of the emissions trading scheme that is the central feature of the clean air legislation passed by the Senate. The WEPCO policy would frustrate electric utilities efforts to achieve cost-effective emissions reductions at existing electric power plants.

EPA's WEPCO decision also frustrates energy policy. WEPCO discourages modifications to improve electric power plant efficiency. WEPCO makes it difficult for electric utilities to maintain reliable generating capacity at existing power plants. The electric utility system is already stretched to the limits. We are hearing predictions of brownouts and possibly blackouts on the east coast if it is a hot summer. In view of the severity of the situation, WEPCO sends the wrong signal to the electric utility industry.

As you may be aware, during the floor debate on the amendment to the Clean Air Act, I introduced a WEPCO amendment. My amendment was comprehensive WEPCO fix. Unfortunately, time did not allow us to work out the details of the amendment with the floor managers. I withdrew my amendment based on Senator Baucus' commitment that in conference he would attempt to find a way to accomplish the goals of my amendment consistent with the overall thrust of the bill.

Today's hearing can help to develop a record for Senator Baucus and the conferees. WEPCO is a complicated issue. They will need all the help they can get.

I regret that I cannot stay for the hearing. I know, however, that with Senator Ford in the chair, I leave the hearing in good hands.

Senator FORD. Mr. Siegel, I am sorry Mr. Gentile could not come; he is a political appointment, and I could have burned him a little more than I can you.

[Laughter.]

Mr. SIEGEL. I am sorry he could not be here either.

[Laughter.]

Senator FORD. But—well, first let me say that you have been an excellent ongoing nonpolitical appointment. And I think Mr. Webb indicated in his statement, how hard you worked to see the things worked out in the benefit of all concerned. So I compliment you for that.

Mr. SIEGEL. Thank you.

Senator FORD. And let me ask you a few questions.

Are gas cofiring technologies commercially available today?

Mr. SIEGEL. They are technically proven. There are not any serious technical issues with gas cofiring. However, there is still information that needs to be gathered to ensure that optimal use of gas in cofiring is understood.

Senator FORD. What about the second generation?

Mr. SIEGEL. The reburning?

Senator FORD. Yes.

Mr. SIEGEL. The reburning technologies are not quite as far along. They have not really been proven at all at large scale. And

under the clean coal demonstration program there are a couple of projects that will be demonstrating reburning.

Senator FORD. What about Parsons and NO_xSO? Did I pronounce that right?

Mr. SIEGEL. Parsons and NO_xSO?

Senator FORD. Parsons process that Mr. Winberg mentions.

Mr. SIEGEL. Yes, those processes as well need further demonstration and also are planned to be demonstrated.

Senator FORD. Planned to be demonstrated. When do you think they will be deployed for this demonstration? When will any of these processes be deployed for demonstration?

Mr. SIEGEL. Well, plans are in place already. We do have all of those processes as part of either the clean coal demonstration program already selected or in joint DOE/industry activities to further them. The cofiring technologies hopefully, if WEPCO does not cause a serious problem, can be demonstrated over the next couple of years, the gas reburning technologies a few years thereafter.

Senator FORD. Other witnesses state that additional research into the proportion of gas to coal in varying boiler types with different coals would help encourage use of the technologies. Do you agree?

Mr. SIEGEL. Yes. Certainly, information is needed on the various boiler types and the ratios of gas to coal and various coal types. But with the several technologies, technology demonstrations that we have planned, we are looking at all boiler types, we are looking at a wide variety of coals, and we are going to be looking at the ratio of gas to coal.

So we think, from a technical perspective, that we have all the bases covered with the demonstrations that currently are under way. Of course, there is always opportunity to gather more information, especially for electric utilities, who are risk adverse. They would like to ensure that any new technology they use has been fully demonstrated, so that there is no—or very limited—risk involved.

So there is always the opportunity for more research. But we think that adequate research is already planned and budgeted for.

Senator FORD. Well, we always get that from the Department, Jack. We never seem to be able to have any input. And I read from your latest statement. I want to read—we will find it here somewhere—Mr. Gentile's. "The additional funding provided in S. 1848 must be weighed against budgetary priorities." I could almost read it without ever—you know, from memory.

"And the fact that the projects it would finance would likely duplicate many ongoing efforts." Now, I have heard that for 15 years. "The Department therefore must oppose this legislation. Consequently"—this is your last paragraph. You know what, you can give it to me verbatim, can you not? Without ever looking at the paper. But just to be sure that I do not make a mistake.

It says, "Consequently, we will embrace the concept," hell, you have already done that, "of cofiring. S. 1848 seems unnecessary, however, in light of current government and industry activities and the need to focus attention more on resolving questions concerning distribution and deliverability of natural gas."

So DOE is concerned about gas availability and deliverability. And that is your question. Wait a minute, wait a minute. GRI be-

lieves that the incremental demand for natural gas would increase only 5 percent of current consumption. And two, in Mr. Winberg's statement he notes that, one-half of the plants in part of the market, 50 percent—50 largest SO_2 emitters are 10 miles or closer to a natural gas pipeline.

Now, what concerns do you have with the information or the statement I have just made?

Mr. SIEGEL. I do not have any concerns. As far as the Department of Energy is concerned, gas availability is not at issue. We think there is ample resource at a reasonable price. The concern happens to be one of how much additional gas is used for cofiring or reburning, the deliverability or the pipeline capacity question. But as I said in my statement, we are going to have to use an awful lot of natural gas in the existing cofired units before that becomes a serious problem.

Senator FORD. If gas prices are higher than currently projected—that is from your statement—it could affect the effectiveness—attractiveness of cofiring as an emissions reductions technique, unless they are offsetting boiler performance improvements.

Your testimony also lists eight ways—eight ways—in which boiler plant operations are improved. Now think about that. You know, you got one statement in one place and another statement in another. But you say this: eight ways in which boiler plant operations are improved by the use of cofiring technologies.

Is it safe to conclude that cofiring is a cost-effective emission reduction technique?

Mr. SIEGEL. To answer that question, I guess, we need a crystal ball with respect to what natural gas prices will be in the future. If natural gas prices remain low, clearly——

Senator FORD. Jack, you are just like Harry Truman's one-armed economist. He just wants to say on one hand it is this, but on the other hand is that. He just wants one arm. Give me a judgment. Can you give me a judgment without representing the administration?

Mr. SIEGEL. Yes. My judgment is that natural gas cofiring and reburning will be cost-effective in a variety of utilities and that other options may be more cost-effective under other circumstances. And that is why we are of the belief that the broad suite of technologies ought to be available to utilities for decisionmaking.

Senator FORD. Well, if I understand where we are going now, we are going to cut off the possibility of any new technologies, maybe with one exception, possibly two, if the year 2000 is the cut-off year for all technologies really that are out there.

And so you are—you know, you are going to have to delay your next awards for any new technologies, are you not, for a while?

Mr. SIEGEL. Very likely, yes. If the Senate supplemental appropriations holds, we will definitely have to do that. Yes, sir.

Senator FORD. So I am very concerned, if we do not go ahead and push for some of these, cofiring would be a bridge. We are talking about 1993 here and some. We are talking about various and sundry cyclone boilers. We have got to test coal and gas and types of coal and different types of boilers and different types of locations. And we have to move on with this.

If we just keep nickeling and diming some of these things—you have never built a white elephant yet. Have you?

[Laughter.]

Mr. SIEGEL. I better not answer that.

Senator FORD. Huh? You never built a white elephant yet, it means that you have been so hesitant, somebody else goes ahead and does that. And you have never been out front. You have been so damn careful, that we have not made any progress at all. We have nickeled and dimed a lot of projects to death.

So we sit here now with a problem that I think can help solve the future. And the problem is you do not want to move on, if we want to give you the money. I have had you guys sit out there and say, if you give it to us, we are not going to spend it. I do not like that. If we give it to you, would you spend it?

Mr. SIEGEL. Certainly, if you give it to——

Senator FORD. In this area?

[Laughter.]

Mr. SIEGEL. If you give it to us and tell us to spend it on this, we will certainly do that.

Senator FORD. Okay, I do not want to ask you any more questions, Jack. That is the answer right there. But let me just make an observation.

DOE is hesitant when talking about the use of 20 percent gas with coal. But I never hear any hesitancy when talking about switching 100 percent to gas from coal in terms of deliverability. I never hear any concern about that.

Mr. SIEGEL. Mr. Chairman, that may be that the deliverability study I mentioned that the Department of Energy is doing with the Federal Energy Regulatory Commission will shed some light on the problems of gas deliverability, and what, if anything, needs to be done to resolve any problems that exist.

Senator FORD. Mr. Webb, in your view, what should the long- and short-term goals of additional gas cofiring R&D be?

Mr. WEBB. Mr. Chairman, we think there should be duplication. Jack has stated that part of the problem is that this bill and this money would duplicate the clean coal technology program.

I do not believe you can do a test on a single type of boiler and get the widespread data and the confidence that utilities need. We think you ought to do additional tests on all three of the primary types of boiler: cyclone, tangential and wallfired and look at different types of coals.

And we need better documentation of the amount of gas to be used to optimize it from both an environmental and an economic standpoint. So I guess what I am saying is that duplication is what is required in order to install the confidence in the utility executives that this the technology I can place on my plant and not subject my rate holders, as you call it, to something that is not cost-effective.

So I think the short-term objective should be to do additional tests of the type that we and industry have with DOE under their clean coal program. The long-term objective would be to mate the reburn, if you would, with the sorbent injection, which are the more advanced technologies and really see, can we get 60 percent NO_x and 50 percent or 60 percent SO_2 reduction at a cost of less

than $100 per kilowatt. If so, we have made a major accomplishment and achievement.

Senator FORD. Do you believe it is a cost-effective emissions reduction technique? Apparently you do.

Mr. WEBB. Yes, sir, I do. It is not for every utility and every situation but for different utilities, and especially those that are just marginally out of compliance, it probably is the best short-term cost-effective measure, especially when you combine it with coal-washing, coal-scrubbing, some of those proven technologies that you have in the coal industry today.

Senator FORD. In your view, is the likely market for cofiring—or where is the market, I guess I should ask, for cofiring technologies?

Mr. WEBB. Mr. Chairman, our assessment would indicate that the primary market are older boilers, where you have an additional life maybe of 10 or 15 years, and you cannot install scrubbers because of the capital cost versus the life of the plant; those boilers that tend to use the medium- to high-sulfur coals, primarily in the midwest and Appalachian regions; and the cyclone boilers we think are the primary market for this technology.

That is the reason our forecast would indicate, you are talking about somewhere between 250 billion and 850 billion cubic feet of additional gas demand, contrasted to nearly 19 trillion cubic that were used this year.

That is the reason we do not think it is a deliverability problem. We think that it is not going to—if you have a plant that is way out of compliance, and it has another 20 years of life, you probably are going to go a technology fix not to a cofiring fix. Okay? So you are not going to use both. So you are not going to use this on all plants and all applications.

There is a market, it is cost effective, it is near term and it can help us get on with meeting these problems in a cost-effective way.

Senator FORD. You mentioned primarily the midwest States. Do you have an estimate of how many plants could benefit from cofiring?

Mr. WEBB. Mr. Chairman, we looked at the 107 and now I think it is a 111 facilities that are singled out under Phase I. If you look at the ones that tend to be less than 500 megawatts, either cyclone fired and are marginally out of compliance, there is probably about 40 to 60 physical units, not plants. There is probably 250 units in those 111 plants; 40 or 50 units that would be the primary candidates.

The reason I cannot give you a more definitive answer is because if some of the lab results can be duplicated in several different tests, that market expands, because we are going to be able to achieve the upper ranges of our technical parameters. If it does not, then you are talking about, you know, probably 40 or 50 units. But that is not a small number when you are trying to make some early Phase I compliance deadlines.

Senator FORD. Well, we are talking about 20 percent to 25 percent of the plants, though, are we not? When you talk about that number of the units?

Mr. WEBB. Yes, it could use 10 percent to 15 percent gas with coal and 20 percent to 25 percent of the plants have been targeted—would be a reasonable target.

Senator FORD. Mr. Winberg, tell the committee more about the Parsons process and the NO_xSO, if that is the way it is pronounced, process. Briefly, what are the benefits of each, and would you consider them second-generation technologies?

Mr. WINBERG. Yes. I would consider them second-generation or perhaps advanced cofiring-type technologies. Basically what they are is catalytic processes that utilize some small amount of gas, 5 percent to 15 percent depending on the technology, and they reduce both SO_2 and NO_x by anywhere from 90 percent to 95 percent.

In addition, they do not create any scrubber sludge. The by-product that the process ends up with is a salable byproduct usually in the form of either sulfuric acid or a sulfur cake, so there is no scrubber sludge associated with them.

I think probably one of the main applications for these technologies are going to be in post-2000 boilers which are going to have to be built in the next century. And since they are going to have the allowance cap to deal with, they are going to have to start out getting 90 percent or 95 percent reduction of both SO_2 and NO_x to minimize the number of allowances they have to purchase.

So clearly those technologies, those second generation technologies are going to play a major role in base-loaded power generation, maybe even as early as the latter part of this decade.

Senator FORD. Do you agree with the assessments you have heard about gas cofiring's role in clean coal—in clean air compliance? Could you add anything? Or do you want to add anything to that debate?

Mr. WINBERG. Well, we clearly agree with GRI on the issue. I think one thing that I might add to the discussion is that in the area of cofiring, which we call basic cofiring—reburn is another type of cofiring—but in the basic cofiring, the demonstrations that have been performed have been done by and large by GRI and the industry. And they have been short term in nature.

And that is one of the problems is that going out and doing field test work, having done some of that, it is very expensive, and it is difficult to get data that is meaningful to electric utilities in what might amount to a week or 2 weeks of testing. It is just not long enough, and there are not sufficient funds out in the industry to carry on a longer term testing, say in the order of 4, 5 or 6 months.

And that is clearly what is needed to give electric utilities the comfort they need to adopt this technology in their strategy. And that is one of the biggest features that this bill would bring, is bring funding to do that type of longer-term testing that is so desperately needed out there.

Senator FORD. So it is your opinion that we do need additional research, we need additional funding, we need to move on with it as soon as possible?

Mr. WINBERG. Absolutely.

Senator FORD. You estimated that gas cofiring would allow utilities to leave 80 percent to 90 percent of current coal supplies in place. How did you arrive at that number?

Mr. WINBERG. What we did is, we looked at the 107 plants, and we combined natural gas cofiring with physical coal cleaning. And we looked at each plant and the type of coal that they used. And

we looked at the cleanability of that coal, because not all coals can be cleaned to the same level.

And our analysis showed that if you looked at coal cleaning and natural gas cofiring to meet a 2.5 pound per million Btu limit, that you could, in effect, preserve approximately 90, I believe, what it was 94 percent of the existing coal, without going into a switching mode. And we thought that those results were very meaningful and substantial in terms of the coal community where we do a majority of our business.

Senator FORD. I like what you say in here.

Senator Bingaman.

Senator BINGAMAN. Thank you, Mr. Chairman.

Let me ask Mr. Siegel if he would just state whether you agree with the estimates that Mr. Winberg has provided that on the capital cost of modifying the plants to accommodate cofiring, I think he indicated they would be anywhere between $2 per kilowatt and $100 per kilowatt for modifying them for cofiring, as compared to at least $150—$150 to $300 per kilowatt to put scrubbers on. Do you agree with those estimates?

Mr. SIEGEL. Yes, sir, I do.

Senator BINGAMAN. In light of those estimates, what are the obstacles that you see to companies going forward with this?

Mr. SIEGEL. Well, the first clearly is ample demonstration of the technology, so that utilities have the confidence that the technology is reliable and can meet the performance and economic goals that exist.

In addition there are regulatory constraints. The other two gentlemen mentioned WEPCO. Clearly that is a concern, a problem, and hopefully one that they will be able to deal with in the next panel.

Senator BINGAMAN. Let me ask, you are saying that one of the obstacles or constraints is ample demonstration of the technology. Given the work that you are presently doing, the Department of Energy is presently involved in, how soon will that ample demonstration of technology occur?

Mr. SIEGEL. For cofiring, probably in the next couple of years, assuming that those projects remain on schedule, and with reburning, a couple of years after that.

Senator BINGAMAN. So you are talking what? 1993 for cofiring, 1995 for reburning? Is that right?

Mr. SIEGEL. Something like that, maybe, a year or so earlier. But it does take time to construct and operate for a reasonable period of time.

Senator BINGAMAN. And how broad based will that be? Mr. Winberg has referred to 107 plants. How many of those plants would be able to make an informed decision about using one of these technologies once those demonstrations——

Mr. SIEGEL. Well, that depends a lot on the utility itself. I would expect some utilities would find those demonstrations—since these are not very complex technologies—they might find these first demonstrations that we are all involved with ample, in order to make some commercial judgments.

Other utilities may not think that is enough and may want to see some more plants built and operated before they would be willing to jump to the technology.

Senator BINGAMAN. So there is really no way to estimate the number of plants that might take advantage of this, given the existing numbers of demonstrations and the existing level of research?

Mr. SIEGEL. Yes, it is very difficult. Then, of course, it depends a lot upon the clean air legislation and the other options that are available for control purposes to the electric utilities. They may find that after analysis of the options based upon their very site-specific conditions that gas reburning or cofiring is the most cost-effective option for them and would be willing to take a little bit more of a risk with this new technology than they otherwise would.

Senator BINGAMAN. Well, the alternative as I understand it for a company if it decides not to do this is essentially to shut down and put on scrubbers. Is that right? Or go out of business?

Mr. SIEGEL. Or they can switch to a lower sulfur coal, which we do anticipate a number of utilities would likely do under Phase I of the clean air legislation. Or there may be some other options. There are some other technologies being demonstrated today that utilities may have the confidence in and may utilize.

Senator BINGAMAN. Do you have any estimate? Like, I gather Mr. Winberg's testimony has 50—the top 50 sulfur dioxide emitting power plants, based on 1985 data. Do you have any estimates as to how many of those top 50 would shift to lower sulfur coal?

Mr. SIEGEL. Our estimates are that approximately half would switch.

Senator BINGAMAN. Half would switch to low sulfur coal. And of the other half do you have any estimate as to how many would put on scrubbers versus use cofiring? Or is it just impossible to tell until you do these demonstrations?

Mr. SIEGEL. It is very difficult to tell at this time. I really do not have a good estimate for that. But clearly, again, we believe that we would like to get a variety of technologies demonstrated, so that the information is available to utilities to make informed and least-cost option decisions.

We think that once that data is on the table, especially for technology like cofiring or reburning, that they will find more of a home in the marketplace than if they are not demonstrated.

Senator BINGAMAN. So really the people who ought to be most interested in seeing this legislation pass are those who are engaged in production of high sulfur coal?

Mr. SIEGEL. I would think people who are involved in the production of high sulfur coal would be interested, certainly the gas industry would be interested, the electric utilities would be interested because they would have another option on the table that would be available to them. So there are a wide variety of interested parties in this technology.

Senator BINGAMAN. When you compare the cost—I know you indicated that other budget priorities impede on this, but when you compare the cost that we are talking about to change some of these plants over to put scrubbers on, it seems to me you are talking about significant investments.

Mr. SIEGEL. That is right. Scrubbers are quite expensive, much more expensive than would be a technology like gas reburning. However, they are a proven technology. They can get in excess of 90 percent sulfur dioxide control. So in those cases where very large amounts of sulfur dioxide removal must take place, scrubbers may be a viable option.

Hopefully, there will be other technologies demonstrated that can also get high percentages of sulfur dioxide removal that would also be considered by utilities; they would be lower cost and will not produce the solid waste that the scrubbers will. But right now scrubbers are the technology to beat.

Senator BINGAMAN. Let me ask either Mr. Winberg or Mr. Webb if there are—if you, first of all, agree with the time frames that Mr. Siegel has indicated as to when this ample demonstration of technology would be done. And what kind of a difference this legislation would make in that time frame, if any?

Mr. WEBB. If I may, Senator. We would agree that by probably 1992 for cofiring and 1994 for reburn you would have some data coming from the tests that we currently have ongoing with industry and DOE. But we do not agree that those very limited number of tests for relatively short periods of time are sufficient.

We think we ought to be demonstrating cofiring on three or four installations and reburn on three or four installations, so we can get the comparative data for the different types of boiler configurations of coal characteristics, et cetera, required to really instill the confidence in the utility sector.

So what your legislation would do—because these tests, if you are talking about basic cofiring on the ones we have run with DOE to date, probably are $3 million or $4 million a piece. If you are talking reburn, they are $10 million to $15 million. That would allow with 50/50 cofunding, probably conduct another four to six tests, which we think are essential really to get this information out there in time for somebody to make a decision before the Phase I compliance deadlines and even the extensions with the clean coal technology.

So that is what we think the legislation does.

Senator BINGAMAN. Mr. Winberg, did you have any comment on that?

Mr. WINBERG. Well, we agree with GRI on that. The only additional comment that I would make is that with basic cofiring the reality is you can put the equipment in, the gas-burning equipment in, in 6 months to 1 year. It is a very short duration of time, plus it is off-the-shelf equipment; you can go and buy it. It is only where you put it in the boiler and how you use it that needs to be demonstrated.

So the turnaround time to get basic cofiring out there in the real world demonstration situation is relatively short. It could be done in a year, and with some amount of testing in 18 months, you could have some results. The reburn will take somewhat longer, because it is more in the beginning stages. But we agree with GRI.

Senator BINGAMAN. Let me—Mr. Webb, you indicated how many additional—if this legislation passed, how many additional projects would you support, or would you believe would be possible both in reburn and in cofiring?

Mr. WEBB. It would appear to us, based on the cost of the tests that we are currently conducting as part of the clean coal program and stuff that a typical reburn test would be $3 million to $4 million—excuse me, a typical basic cofiring test, which you could get it conducted in like 18 months and get the data.

A typical reburn tests are going to cost from $10 million to $15 million each. So if you are talking about $27 million, you match it with at least that much, you are talking about $55 million to $60 million. That ought to allow us to conduct anywhere from four to six additional tests total. It would appear to us probably we ought to try to do two or three reburn quickly and get a diffusion of data out there and then concentrate on doing two real good reburn tests in addition to the two we have planned as part of the DOE program.

Senator BINGAMAN. Mr. Siegel, did you have any comment on what was just suggested as a way to spend this money, if in fact, the Congress would authorize and appropriate it?

Mr. SIEGEL. No, I would agree. If Congress authorizes and appropriates the funds, we would work with industry to ensure that they are utilized to gather the data that industry feels is necessary for them to make informed decisions. And I agree with the comments made by the two gentlemen.

Senator BINGAMAN. Do you have any estimates, Mr. Siegel, as to the amount of gas that would be used in these power plants, if this technology was in fact employed?

Mr. SIEGEL. For cofiring and reburning, we are talking about 10 percent to 20 percent of the Btu input to the existing coal-fired power plants. What that equates to in terms of TCF of natural gas, I do not have off the top of my head, but we can certainly provide that for the record. Oh, yes, we do have it, right off the top of my head.

[Laughter.]

Mr. SIEGEL. Off the top of my head, if we use 10 percent natural gas for cofiring and reburning on all of the coal-fired power plants in the country, that is 14 gigawatts of coal-fired power plants, that would equate to about 1.5 quadrillion to 3 quadrillion Btu's of natural gas. Which is how many? Okay, 1.5 quadrillion Btu's for 10 percent, 3 quadrillion Btu's for 20 percent natural gas in those cofired units.

Senator BINGAMAN. Okay, all right.

Those are all the questions I had, Mr. Chairman. Thank you very much.

Senator FORD. I want to ask one question of Mr. Siegel. Would not the cofired technology versus the scrubber technology take a lot less room to install as it relates to the scrubber? Space becomes a problem——

Mr. SIEGEL. Yes.

Senator FORD [continuing] With some of these, and under the circumstances, cofired would take far less area and probably work where you have very limited space, would it not?

Mr. SIEGEL. Yes, Mr. Chairman, that's a very good point. Scrubbers do require a great deal of space, and in some existing utilities, the space is not available. A gas technology cofiring or reburning would only require the space necessary for the pipeline.

Senator FORD. And also, we would get to the NO_x on this, in addition to SO_2.

Mr. SIEGEL. That is right, and scrubbers do not remove NO_x.

Senator FORD. So, you seem to be saying that it has all the great potentials. The other two gentlemen believe it, and I am beginning to get that from you now, that it has no sludge, we don't have to worry about land to bury it, you know, there is a lot—probably take care of the two plants that are furnishing energy to the little plant down there in West Kentucky called Uranium Enrichment, you know.

Mr. SIEGEL. I have heard of that. Yes, sir.

Senator FORD. Yes, sir, that is good enough right there.

[Laughter.]

Senator FORD. You do not have to go any further, that is good enough.

We have been joined by Senator Wirth, and we are delighted to have you. If you have an opening statement, Tim, we would like to have it.

Senator WIRTH. No, I do not.

Senator FORD. And if you have some questions——

Senator WIRTH. I do not, unless you would like me to make one.

Senator FORD. You did not have to ask that, you knew the answer.

[Laughter.]

Senator WIRTH. Very briefly, have you all seen the proposal that the Council of Economic Advisors is going to be suggesting to us in the next panel?

Mr. WEBB. No, sir, I have not.

Senator WIRTH. You have, Mr. Siegel?

Mr. SIEGEL. Yes.

Senator WIRTH. The purpose of my question was to see if you had any reactions to that while we had you here. You all have given a great deal of thought to this. Mr. Siegel, do you want to——

Mr. SIEGEL. Sir, I am staying for the next panel, so I would not mind, if you do not mind——

Senator WIRTH. You are going to be here for the next panel?

Mr. SIEGEL. Yes, I am.

Senator WIRTH. You have not seen it, Mr. Webb?

Mr. WEBB. No, I have not.

Senator FORD. We have only got about 10 minutes before the hearing.

Senator WIRTH. It has been floating around. I just thought they might have a reaction to it. Okay, thank you, Mr. Chairman.

Senator FORD. Well, it has been floating around, but as far as coming down to official to the committee, we have not seen it. I did not mean to interrupt, but——

Senator WIRTH. No, I have no further questions.

Senator FORD. Does anybody wish to respond to Senator Wirth?

Mr. WEBB. I have not seen it, Senator.

Mr. WINBERG. Nor have I.

Senator WIRTH. Thank you, Mr. Chairman.

Senator FORD. Thank you, Senator Wirth, and thank you gentlemen, and Jack, I sure hope we give you some money so you can

proceed with this, that you are on the record saying you will. Thank you very much.

Since I am bilingual, bad English and Southern, I hope I do not ruin the next gentleman's name. Mr. Schmalensee? Is that reasonably close?

Mr. SCHMALENSEE. Absolutely correct, Mr. Chairman.

Senator FORD. Wonderful. Then I get around to Mr. Blake and Mr. Roberts and Mr. Maassel.

Mr. MAASSEL. Maassel.

Senator FORD. Maassel. That was more trouble than the other one.

Gentlemen, we are delighted to have you, and we will start with Mr. Schmalensee, and we will move to his right to Mr. Blake and Mr. Roberts and so forth. Would you identify any EPA or DOE representatives who are accompanying you, please sir?

Mr. SCHMALENSEE. Thank you, Mr. Chairman. I have with me Greg Foote, Assistant General Counsel of EPA, and a number of other EPA staff and Jack Siegel from DOE and a number of DOE staff and Howard Gruenspecht, as well, from the CEA staff.

Senator FORD. No wonder they are standing in the hall.

[Laughter.]

Mr. SCHMALENSEE. I tried to respond fully to your request, Mr. Chairman.

Senator FORD. Fine. I hope that they will be able to answer questions following the testimony. You may proceed.

STATEMENT OF RICHARD SCHMALENSEE, MEMBER, COUNCIL OF ECONOMIC ADVISERS, ACCOMPANIED BY JACK S. SIEGEL, DEPUTY ASSISTANT SECRETARY, OFFICE OF COAL TECHNOLOGY, DEPARTMENT OF ENERGY; GREGORY B. FOOTE, ACTING ASSISTANT GENERAL COUNSEL, OFFICE OF GENERAL COUNSEL, ENVIRONMENTAL PROTECTION AGENCY; AND HOWARD GRUENSPECHT, SENIOR STAFF ECONOMIST, COUNCIL OF ECONOMIC ADVISERS

Mr. SCHMALENSEE. Thank you very much, Mr. Chairman. I am very pleased to be given this opportunity to discuss with you the very complex issue that has come to be referred as WEPCO and to present the administration's position on this issue.

I am going to limit the scope of my remarks in two ways. First, I am not a lawyer, and I am not going to pretend to offer legal opinions or to interpret past decisions. Second, I'm going to limit my focus, as much of the discussion has been limited, to the electric utility industry. Following roughly the structure of my written statement, I would like to proceed as follows.

First, by way of background, I would like to outline the economics of the WEPCO issue and mention some of the key related uncertainties. Then I want to answer one of your questions, Mr. Chairman, and talk about regulatory impediments to repowering and retrofit technologies. Then I would like to address the other question you put directly in your letter, and discuss whether or not the WEPCO issue is handled adequately in the Senate and House Committee Clean Air Bills.

Fourth and finally—this of course gives away the answer to the third question—I would like to outline a set of principles that the administration believes provide the foundation for a legislative approach to WEPCO that will protect local air quality values and also significantly reduce uncertainty affecting investment decisions in the electric utility industry.

Senator FORD. At this point, would the other three panelists, if you have not seen the legislative proposal, that you listen to it very closely, so that you might be able to give your opinion of what the proposal might be. I think that is probably a real important question to be answered in this hearing. I apologize for interrupting your statement, but we need all the answers we can get.

Mr. SCHMALENSEE. Mr. Chairman, if I had extra copies, I would be happy to distribute them, but unfortunately I do not. We gave them all away.

Senator WIRTH. How long is it?

Mr. SCHMALENSEE. The testimony itself is 12 pages, the key discussion is in the last four.

Senator WIRTH. This is of your testimony or the proposal itself?

Mr. SCHMALENSEE. The proposal itself it contained, basically, in the last four pages of the testimony.

Senator WIRTH. Would you all like to have a copy of that, to look at it while——

Mr. Roberts: I have had a chance to review it.

Senator WIRTH. Excuse me?

Mr. Roberts: I have had a chance to review it, I do not know——

Senator FORD. The staff is taking care of it now.

Senator WIRTH. Oh, okay.

Senator FORD. Thank you for your suggestion.

Mr. SCHMALENSEE. Mr. Chairman, the WEPCO issue, turning first to the basic economics, as a once and future economics professor. The WEPCO issue arises in large part because it is cheaper to control new facilities than to retrofit old facilities. Because of this, U.S. environmental policy has historically imposed tougher standards on new than on old facilities. This regulatory policy, of course, provides an extra incentive to extend the life of old facilities, rather than to build new facilities.

The WEPCO issue reflects the need to counteract this incentive by rules that decide when a modified old facility is really a new facility, and the difficulty of framing fair rules, workable rules for this purpose.

The acid rain program in the proposed Clean Air Amendments make this issue more important. There is a tension between the long-standing, source-by-source approach to local air quality problems, to maintaining local air quality values under the existing Clean Air Act and the flexible, regional and national approach to sulphur dioxide control in the Senate and House committee bills.

Under existing rules for deciding when an old source should be subject to new source review, some actions that would be cost effective ways of complying with the sulphur dioxide provisions may trigger new source review, thus making them more expensive than they otherwise would be.

The Clean Air Act, the existing Clean Air Act specifies that any modification to an existing source that increases source-specific

emissions of any regulated pollutant must go through new source review, even if the modification decreases emissions of one or more other pollutants. Modification is defined in the Act as any physical change in or change in the method of operation of a stationary source which increases the amount of any air pollutant emitted by such source, or which results in the emission of any air pollutant not previously emitted.

The key question here, is the operational, regulatory definition of modification. By regulation, EPA has defined routine maintenance repair and replacement as not constituting a modification. Beyond that, for new source performance standards purposes, changes that do not increase hourly emissions rates are not modifications, while for PSD and non-attainment purposes, changes that do not increase total annual emissions are not modifications.

The WEPCO case in related developments, in concert with the sulphur dioxide control program have focused attention on at least three sets of concerns regarding future EPA actions.

First, there is concern that the increase test for PSD or non-attainment review would trigger reviews for physical or operational changes that would provide direct economic incentives to increase capacity utilization, even if hourly emissions rates were reduced at the affected unit and total emissions of all pollutants were reduced once utilization changes at other units were taken into account.

Second, there is uncertainty regarding when actual emissions will be used, when potential emissions will be used and when differences between past actual emissions and future potential emissions will be used for triggering new source reviews. This is compounded by uncertainty regarding the importance of the WEPCO court's distinction between like kind replacements and other changes.

Third, considerable uncertainty attaches to EPA's future definition of routine, and of actual and potential emissions.

Let me now turn to the question you posed in your letter of invitation, Mr. Chairman, to talk about regulatory impediments to market penetration of repowering technologies and retrofit technologies, such as natural gas cofiring, stemming from EPA's so called WEPCO policy. This is a difficult question, since many factors affect the fusion of new technologies in any sector, perhaps more than usual here, and assessing that relative importance is inevitably difficult.

In principle, there are two offsetting, regulatory forces in this context. First, because the regulatory distinction between new and old sources provides incentives to prolong the life of old sources, it tends, to some extent, to promote the adoption of retrofit technologies in particular, but because this distinction makes it necessary to decide that some changes in old plants make them into new plants, it makes countervailing impediments to the penetration of these technologies necessary. On the one hand, there is the new source/old source distinction. On the other hand, there is the administrative reaction to it.

We know that fear of new source review matters. It certain matters under present conditions, but it is difficult to say how much is a quantitative matter. Approximately half of the utilities selected as host sites for clean coal technology demonstrations have ex-

pressed moderate or strong concerns regarding the WEPCO policy. Only one project has cited WEPCO as a major factor in withdrawing from the demonstration program, however, but one other was significantly delayed by WEPCO concerns.

My impression is that the net affect of these regulatory forces has generally been to slow the penetration of these technologies somewhat. But I find myself unable to give conclusive, quantitative evidence to support that impression.

Your letter also posed a second question, and that was whether or not the WEPCO issue was addressed adequately in the Clean Air Amendments, as recently passed by the Senate and as currently pending in the House of Representatives.

To put these developments in context, I want also to briefly discuss some recent EPA actions in this area. And in the interest of time, let me just mention the discussion in my written testimony of a recent study done for the utility air regulatory group, by ICF, Inc.

This is a study which concluded that EPA's WEPCO policy could potentially quadruple the cost of acid rain control. We think this study greatly overstates the likely impact of WEPCO for reasons that are outlined in my written testimony. Let me turn first to EPA and then to the Senate and House bills.

The WEPCO decision, as I understand it, gave EPA considerable discretion, which has led some to express fears that implausibly strict policies could be adopted. Without new legislation, administration action by EPA can resolve most uncertainties except, of course, for those related to judicial review, and future administrative decisions.

Since the WEPCO decision was handed down on January 19, EPA has sought to reduce uncertainties surrounding its policies. To date, EPA has issued several no action assurances to temporary clean coal technology demonstration projects to prevent new source reviews from being triggered when clean coal technology equipment is removed at the end of the project. As my written testimony mentions, these letters are not—these no action letters are not panaceas, but they are steps in the right direction.

Most recently, EPA sent a letter to the Indiana Department of Environmental Management, stating that EPA's interpretation of current rules would exempt the NIPSCO-Bailey clean coal technology project from new source requirements. This widely distributed letter is intended to clarify EPA's policy, and sheds light on a draft, interpretative ruling now under review at EPA.

Let me now turn briefly to the Senate and House bills, and if I may, refer you to my written testimony for more details. As passed, the Senate bill contains no broad or generic WEPCO provision, but it does deal explicitly with commercial repowering and with clean coal technology demonstration projects, retrofit projects, gas conversion projects and other pollution control projects.

Definitive copies of the House Committee bill are not yet available. As I understand it, however, that bill now contains two broad, generic WEPCO provisions. There is apparently some tension between them, and I am told that their net impact is difficult to determine. The House bill deals with repowering and with clean coal technology demonstration projects. Both bills exempt temporary

clean coal technology projects from new-source performance review, from PSD and non-attainment provisions. Their coverages of—sorry, new source performance standards. Their coverages of other projects differ and are less comprehensive.

The question before me is, whether, in light of all of these—whether all of these developments constitute an adequate response to the WEPCO issue. These developments certainly move in the right direction, and given EPA's ability to deal with this issue administratively, there is a good case for reliance on Administrator Reilley's good sense to maintain a sound administrative approach in the future.

Nonetheless, the administration's position is that, particularly in light of the special burdens placed on the electric utility industry to control acid rain and the importance of flexibility to that program, differences in the interpretation among a number of court decisions, uncertainties as to how different decisions will be reconciled, differences between the House and Senate bills, recent history of policy in applying new source review to modifications of existing utility plants, and the hazards of judicial review of EPA action—I'm sorry for the length of this sentence—a broad, clear, generic provision to deal with the WEPCO issue should be included in the final clean air bill.

Let me now turn to the sort of broad, generic provision that the administration could support. Let me make clear at the outset that the administration views the acid rain or acid deposition program and the pending amendments as a supplement to, not a substitute for existing clean air programs. In particular, local air quality values should not be compromised.

And let me add an important disclaimer, neither these remarks nor my written testimony should be taken as proposing specific legislative language. My testimony was prepared under inevitable time pressure by an economist, not a lawyer, and reflects intensive interagency discussions. I think it fairly represents the principles that the administration supports, but I cannot promise you that there are not mistakes or problems in the details.

Taking account of the need. both to protect local air quality——

Senator FORD. Is there anything in this statement that you will back up?

[Laughter.]

Mr. SCHMALENSEE. I will back up the general principles. If you ask me why a comma is here rather than there, I will——

Senator FORD. You know, I never worried too much about commas, as long as I understood the language.

Mr. SCHMALENSEE. Well, Mr. Chairman, I must say, this is as complex a regulatory issue as I have ever tangled with, and I think we have it straight, and I think the statement says what we mean. But given the level of effort that has gone into it, I am fully prepared to learn that we have misplaced a comma or a section number or a letter or something someplace. This is not intended to be tentative testimony, as regards to principles in the thrust, merely to point out that the words are not intended to be enacted immediately.

Taking account of the need both to protect local air quality, to provide flexibility and certainty to enable utilities to make the am-

bitious emissions reductions required under the acid rain programs at reasonable cost, the administration supports a broad, generic legislative resolution to this issue that has seven basic elements, and this is the material that I referred to earlier as being in the back end of the written statement, beginning, I believe, on page 11.

First, the distinction between routine and non-routine, physical and operational changes to electric utilities, steam electric generating units, should be retained. But to reduce uncertainty, EPA should be instructed quickly—the written statement says, I believe, within 18 months of enactment—to issue guidance for use by permitting authorities in determining criteria under which refurbishment projects would be considered routine or non-routine. This has been a source of uncertainty, and we would recommend that EPA speak to it.

Second, to protect local air quality values, any non-routine physical or operational change that results in a net increase in the maximum hourly emissions rate, or actual emissions of any regulated pollutant, in an non-attainment area, where there is a local air quality problem, would be subject to the review and permitting requirements of part D of title I of the Clean Air Act.

PSD increments and visibility protection limitations under Part C must also be protected in a way that minimizes compliance costs. One way to do this, which revolves around reliance on earlier modeling exercises, and does not automatically compel remodeling, is sketched in my written testimony, and we can go into those difficult details, if you wish.

Third, as in the Senate and House Committee bills, temporary clean coal technology should be exempted from new source performance standards, PSD and non-attaintment provisions.

Fourth, in considering all other non-routine changes, that is to say, other than temporary clean coal projects, we would distinguish between utility pollution control projects, and other non-routine changes and apply different tests to each.

Let me now describe how the distinction is made, and then I will discuss the two separate tests. We would follow language that has been introduced, I believe, by Congressman Sharp in the House, to use what amounts to an intense standard, as the ultimate test for whether a project is a utility pollution control project, that is, any non-routine physical change in or change in the method of operation of an existing steam electric generating unit for purposes of reducing emissions at that unit, in order to comply with the acid deposition title of the Clean Air Act should constitute a utility pollution control project. The key words there are, of course, for purposes of reducing emissions at that unit, et cetera, et cetera. This would include, among other things, gas cofiring and reburning.

This basic intense standard should be applied to a project, a set of roughly contemporaneous changes, rather than separately to each change.

Nonetheless, this definition leaves some residual uncertainty, because when a plant is idle to permit physical changes, in particular, aimed at reducing emissions rates, say, of sulphur dioxide, it is often economical to make other changes as well, at the same time. To reduce uncertainty regarding the status of what one might call mixed projects, projects in which part of the changes are directly

related to compliance with the acid deposition title, and part of the changes may be unrelated, we would specify that any project is a utility, pollution control project if it passes two tests.

First, those physical or operational changes, unrelated to compliance with the acid deposition title, must cost 20 percent of the total cost of the project—can cost no more than 20 percent of the total cost of the project. And second, any unit that is subject to Section 407 of the Senate bill, which deals with NO_x emission standards, must comply with any applicable final rule that has been issued under subsection B of that section.

The intent is, if one looks at that section, that there is a phasing of rule making for different boiler types. It is unreasonable to require boiler type for which no standard has been issued to comply with an unissued standard in a project. It is, however, reasonable to require a compliance with a rule, even accelerated compliance, as a condition of, as it were, automatic qualification as a utility pollution control project.

Fifth, utility pollution control projects, thus defined, would be evaluated in terms of their impacts on maximum hourly emissions rates, following current policy toward new source performance standard reviews, except, of course, in non-attainment areas, whereas, I indicated above, you would need to look at impacts on actual emissions. Again, there is some more detailed wording in the written testimony.

Let me attempt, at least, to cut to the chase. For other non-routine changes—this is the sixth item—it is desirable to apply a comparison of actual emissions levels in representative before and after periods, to require EPA to allow utilities to reduce costs by employing comparisons of total within state—within company actual emissions where EPA is the permitting authority, and to give States the option to do this where EPA is not the permitting authority.

And finally, if these tests for avoiding new source review are not met, and a new source review is triggered, we believe that best available control technology, BACT, the BACT standard for NO_x should be the standard set forth in rules promulgated under Section 407(b) of the Senate bill. I wish I could have offered you a simple solution to this complex issue, but it does not appear to us to be one that can be simply dealt with.

I thank you, Mr. Chairman, members of the Subcommittee, for giving me this opportunity for indulging—for your patience in listening to this long testimony. I would, of course, be pleased to respond to any questions you might have.

[The prepared statement of Mr. Schmalensee follows:]

TESTIMONY OF RICHARD SCHMALENSEE
MEMBER, COUNCIL OF ECONOMIC ADVISERS

ON
S. 1868
NATURAL GAS CO-FIRING PROMOTION ACT OF 1989

BEFORE THE
SUBCOMMITTEE ON ENERGY RESEARCH AND DEVELOPMENT
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

May 8, 1990

I am very pleased to be given this opportunity to discuss with you the complex set of issues that have come to be referred to as WEPCO. I will limit the scope of my remarks in two ways. First, as I am not a lawyer and claim no expertise whatever in environmental law, I will not pretend to offer my own legal opinions or to predict future judicial decisions. Second, as the electric utility industry is the focus of most discussions regarding WEPCO -- and of virtually all discussions regarding WEPCO's interaction with the various Clean Air bills -- I will limit my remarks to that industry.

Mr. Chairman, you posed two specific questions in your letter. First, you requested testimony on regulatory impediments to market penetration of repowering and retrofit technologies stemming from EPA's so-called "WEPCO" policy. Second you asked for a discussion of whether or not the WEPCO issue was addressed adequately in the Clean Air Act amendments as recently passed in the Senate and as currently pending in the House.

In regard to the first question, it is extremely difficult to separate the incremental effect of "EPA's so-called 'WEPCO' policy" from other influences on the market penetration of repowering and retrofit technologies. Anecdotal evidence and common sense both suggest that the modification rule as currently applied by EPA, has by itself probably had some discouraging effect on the market penetration of repowering and retrofit technologies. It is important to recognize that pollution control retrofits or other modifications which cause emissions of <u>all</u> pollutants to <u>decrease</u> at the source being retrofitted will not trigger a new source review. The main controversy in WEPCO revolves around the way in which the before and after emissions being compared in applying the increase test are calculated.

As to the second question, adequacy is inevitably in the eye of the beholder, and the proposed Clean Air Act amendments (and certain administrative developments that I shall discuss) do move in the right direction especially with respect to clean coal technology. After a careful look at the matter, the

Administration has formulated a set of principles that it believes provide the foundation for a legislative approach to WEPCO that will protect local air quality values and also significantly reduce uncertainty affecting investment decisions in the utility industry. These principles are outlined at the end of my testimony.

Basic Issues and Problems

Environmental policy has historically imposed more stringent obligations on new facilities than on old facilities. The main substantive rationale for this distinction is that it is often more expensive to retrofit existing plants to reduce emissions to some level than to incorporate controls into the design of new plants to attain that same level. The distinction between new and existing facilities may also be attractive because the interests of existing facilities are more vigorously defended than the interests of those that do not yet exist when a regulatory program is established.

For whatever reason it is introduced, the distinction between new and old plants may create strong incentives to prolong the lives of old plants in order to avoid tougher new-plant standards. The WEPCO issue, in its present form, basically reflects the difficulty of using further regulation to counteract this incentive.

Specifically, in a regime where existing facilities receive more favorable treatment than new ones, it becomes necessary to decide when changes to an existing source make it into a new source for regulatory purposes. It is easy to agree that replacement of everything but a plant's outer shell should trigger new source requirements. It is also easy to agree that routine maintenance, of the sort that is regularly done on specific plants, is not capitalized, and has no effect on emissions, ought <u>not</u> to do this. It is, however, extraordinarily difficult to get even reasonable, well-informed people to agree on where the line should be drawn between these extremes. In recent years, industry plans to rehabilitate existing units rather than to build new ones has focused increased attention on this issue, and EPA enforcement policies and court decisions in WEPCO and related cases have not resolved important uncertainties regarding both the present location of the line and where it should be drawn in the future.

In the abstract at least, the best way to deal with the incentive problem posed by the distinction between new and old sources is to shift from source-specific control requirements to area-wide emissions ceilings -- but only where this can be without compromising local air quality values. EPA's bubbles and offsets programs are moves in this direction. The President

proposed a significant further move in this direction: amendments to the Clean Air Act to deal with sulfur dioxide emissions, which cause acid rain, by a system of tradable allowances coupled with a nationwide cap on those emissions. We are gratified that this approach has been retained in the Senate bill and, we understand, in the bill ordered to be reported by the House Energy and Commerce Committee. An important reason for the attractiveness of this approach is its ability to deal with the environmental problems posed by very old plants with high emissions in a fair and cost-effective manner. However, it must be recognized that the adoption of this flexible, cost-minimizing approach to acid rain control adds a new dimension to the WEPCO issue.

That is, there is a tension between the longstanding source-by-source approach to local air quality problems under the existing Clean Air Act and the flexible approach to sulfur dioxide control at the regional and national level in the Senate and House Committee bills. Under the latter approach, electric utilities are free to reduce emissions any way they can -- by fuel-switching, scrubbing, changing dispatch orderings, encouraging conservation, or doing other things nobody has yet thought of. They are even free to increase emissions from some plants, as long as they remain within the limits of any applicable State Implementation Plan (SIP) and purchase allowances from others who have decreased emissions below levels they would otherwise be required to reach.

The tension arises in part because cost minimization requires that utilities be free to reallocate their generation loads as part of their compliance strategies, but those reallocations may also reallocate emissions among generating units. But actions aimed at reducing sulfur dioxide emissions, such as a change in fuels or the installation of pollution control equipment, that require modifications to generating units may trigger new source review depending on the way in which "before" and "after" emissions used in applying the net increase test are calculated. The modification rule may be triggered even if the "after" emission level does not violate any air quality standards at the local level.

WEPCO-Related Uncertainties

The Clean Air Act specifies that modifications to an existing source that increase source-specific emissions of any regulated pollutants that affect local air quality must go through new source review -- even if the modification decreases one or more other pollutants. New source review has two components. The Prevention of Significant Deterioration (PSD) program limits air quality deterioration from new or modified sources siting in already clean areas; and the non-attainment

provisions expedite attainment in areas that violate one or more of the National Ambient Air Quality Standards (NAAQS).

"Modification" is defined in the Act as "any physical change in, or change in the method of operation of a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." By regulation, EPA has defined "routine maintenance, repair, and replacement" as not constituting a "modification." For NSPS purposes, changes that do not increase hourly emissions rates are not "modifications," while for PSD and NA purposes, changes that do not increase total annual emissions are not "modifications."

The WEPCO case and related developments have focused attention on at least three sets of concerns regarding future EPA actions. First, there is concern that the "increase" test for PSD/NA review would trigger reviews for any physical or operational changes that would provide a direct economic incentive to increase capacity utilization, even if hourly emissions rates were reduced at the affected unit and total emissions of all pollutants were reduced once utilization changes at other electric utility units were taken into account. Second, there is uncertainty regarding when actual emissions will be used, when potential emissions will be used, and when differences between past actual emissions and future potential emissions will be used for triggering new source reviews. This is compounded by uncertainty regarding the importance of the WEPCO court's distinction between "like-kind replacements" and other changes. Third, considerable uncertainty attaches to EPA's future definitions of "routine maintenance" and of "actual" and "potential" emissions.

Impediments to Market Penetration

Senator Ford's letter of invitation requested testimony regarding "regulatory impediments to market penetration of repowering technologies and retrofit technologies, such as natural gas co-firing, stemming from EPA's so-called 'WEPCO' policy." The January 1989 report of the Innovative Control Technology Advisory Board to the Secretary of Energy identifies three categories of impediments: economic problems, referring to capital cost risk, and performance and operating cost risk; problems in PUC regulation, referring to electricity-rate regulatory risk and the siting and approval process; and problems with environmental regulation, referring to environmental compliance risk, environmental permitting and regulatory delays, and regulatory inflexibility. The ICTAB study does not provide a basis for quantifying these different effects, and I am even uncertain how any such study might be structured so as to

disentangle the multiple forces influencing the market penetration of these technologies.

DOE is, of course, in contact with utilities selected as host sites for CCT demonstrations. They have indicated that approximately one-half of these utilities have expressed moderate or strong concerns regarding the WEPCO policy. Only one project has cited WEPCO as a major factor in withdrawing from the demonstration program. One other project was significantly delayed by WEPCO concerns. To this purely anecdotal evidence, I can add a few qualitative observations.

It must be recognized that because the regulatory distinction between new and old plants provides incentives to prolong the life of old plants, it tends to some extent to promote the adoption of these technologies. Because this distinction makes it necessary to decide that some changes in old plants make them into new plants, however, it makes some countervailing impediments to the penetration of these technologies necessary. My impression is that even before the WEPCO decision, the net effect was to slow the penetration of these technologies somewhat, but, as noted above, conclusive evidence is lacking.

It is correspondingly more difficult to determine the incremental effect of "EPA's so-called 'WEPCO' policy" on the market penetration of these technologies. Certainly the installation of either repowering or retrofit technologies is likely to be considered "nonroutine" under that policy. And it is my impression that the uncertainties discussed above have led to fears that use of these technologies would lead to failure of the "increase" test for PSD/NA review, particularly if repowering or retrofitting would lead to increases in capacity utilization. It is important to note that such increases are likely to be common in this context: modifications that increase the efficiency of an old unit generally make it efficient and economical to increase utilization. The acid rain program will increase the frequency of this pattern, since changes to a unit that reduce its sulfur dioxide emissions rate or that are naturally accompanied by other changes that have this effect generally provide additional incentives to use that unit more intensively and to reduce generation elsewhere.

It is thus hard to escape the conclusion that current law, as recently interpreted, has by itself had some discouraging effect on the market penetration of repowering and retrofit technologies. The available evidence does not allow us to determine whether that effect is large or small. And it is important to consider legislative proposals to reverse or eliminate that effect in light of recent administrative developments.

Recent Developments

Senator Ford's letter of invitation requests a discussion of "whether or not the WEPCO issue was addressed adequately in the Clean Air Act Amendments as recently passed by the Senate, and as currently pending in the House of Representatives." I would like to begin my response with a broader discussion of EPA's application of the modification rule to the electric utility sector.

The application of the modification rule to refurbishments clearly has very significant cost implications for the electric utility sector. For some facilities, exposure to the modification rule will significantly alter decisions regarding the timing of refurbishment or maintenance. In some cases, a decision may be made to opt for early retirement instead of a refurbishment plan. Many of the costs associated with the application of new source review to modifications at existing units are largely independent of the enactment of the new acid rain program -- a fact which does not make them any less important from the perspective of the utilities that are significantly affected by both programs.

EPA believes that projects as extensive and nonroutine as the WEPCO Port Washington project will be the exception rather than the rule. To date, WEPCO is one of the only utility plants to trigger the modification provisions at existing units under new source review provisions. However, given the forecasted reliance on refurbishment in the electric utility sector it would be difficult to argue that no more WEPCOs are in store.

It must be noted that compliance actions taken in response to the acid rain program could increase the number of existing facilities facing new source review as compared to a "business as usual" scenario. Consideration of this effect would probably dissuade utilities from engaging in some projects identified as part of the low cost compliance strategy that, for purposes of Administration cost estimates was based on an assumption that concerns over new source review had no role in compliance decisions. Conversely, compliance with the acid deposition control program could raise the costs of the new source review program if it increases the number of facilities subject to the modification rule. The interaction between these programs suggests the need to revisit the former while enacting the latter.

As I understand it, the court decision in WEPCO gave EPA the authority to continue its recent enforcement policies (with the exception that the so-called "actual-to-potential" standard for PSD purposes was ruled invalid for at least some changes), but did not compel it to do so. Thus EPA is free to return to the

enforcement policy (or, more precisely, the operational definition of "modification") that prevailed until the last few years. Moreover, much of the concern in this area stems from uncertainty regarding EPA's future policies, uncertainty that has led some to express fears that implausibly strict policies could be adopted. Without new legislation, administrative action by EPA can help to resolve this uncertainty. Such action is of course subject to the vagaries of judicial review and future administrative decisions.

In the limited time that has elapsed since the WEPCO decision was handed down on January 19, EPA has moved to clarify its policies. EPA has sought to reduce uncertainties surrounding its position with respect to clean coal technology and other utility projects that could be affected by its NSPS and New Source Review policies. To date, EPA has issued several research-related "nonaction" assurances to temporary CCT projects to prevent new source reviews from being triggered when CCT equipment is removed at the end of the project. Such assurances are not, however, a panacea: they can leave recipients in technical violation of the Clean Air Act and subject to citizen suits. DOE reports that some projects have rejected the offer of a formal no-action assurance in order to maintain a lower profile regarding such technical violations.

Most recently, EPA sent a letter to the Indiana Department of Environmental Management stating that EPA's interpretation of current rules would exempt the NIPSCO-Bailey CCT project from new source requirements. This letter is intended to clarify EPA's position that if a source solely adds or enhances systems or devices whose primary functions are the reduction of air pollution, and that are determined (by the Administrator) to be not less environmentally beneficial than any emission control system or device it replaces, if any, such activities would not constitute a physical or operational change triggering new source review. The letter states that a forthcoming Interpretative Ruling now under review at EPA would apply this policy to both temporary and permanent projects under the CCT program. While EPA will continue to move administratively, legislative action is also under consideration.

Let me now, as you requested, turn to the Senate and House Committee bills. As passed, the Senate bill contains no broad or generic "WEPCO provision," but it does deal explicitly with commercial repowering, with clean coal technology (CCT) demonstration projects, and with certain other projects.

Section 409(d) exempts repowered units qualifying for a compliance date extension from NSPS if there is no increase in hourly emissions of any pollutant regulated under the Clean Air Act; it does not deal with PSD or NA reviews. Section 415(e)(2) exempts temporary CCT demonstration projects from NSPS, PSD and

NA provisions. Section 415(e)(3) provides exemptions for permanent CCT demonstration projects and certain other projects from PSD and NA review under certain conditions but does not address NSPS review. Repowering projects are exempt from PSD and NA review if potential emissions do not increase. Retrofit projects (e.g., scrubbers), other pollution control projects, and gas conversion projects are exempt if there is no significant increase in actual emissions of any pollutant regulated under the Act, with a rebuttable presumption that the project will not increase the unit's capacity factor. Some have suggested that this presumption may be easily rebutted by either the utility's own announced plans for compliance with the acid rain program or by consideration of the likely impact of a project on utility dispatch plans. (Fuel switching is characterized as a retrofit if physical changes are necessary to accommodate the new fuel.)

Finally, let me comment briefly on the House Committee bill. I must note at the outset that definitive copies of the House bill were not available as this testimony was prepared so that there is some chance that I will mis-characterize its provisions and their likely effects. As I understand it, the House Committee bill now contains two broad, generic "WEPCO provisions": Sections 512(b) and 707. There is some tension between them, and I am told that their net impact is difficult to determine.

Section 508(c) of the House bill exempts repowered units qualifying for a compliance date extension from NSPS review. Such units are also exempt from PSD and NA provisions if potential emissions after the change, assuming a 70 percent capacity factor, do not exceed actual emissions before the change. Since repowering often follows a period of low capacity utilization, we expect this exemption to apply only when significant investments in pollution control are made along with repowering. Section 515(b) of the House bill exempts temporary CCT demonstration projects from NSPS, PSD, and NA provisions. Permanent CCT demonstration projects are exempted by Section 515(c) from these same provisions only if those projects pass the same "current actual to potential emissions at 70 percent utilization" test that would be applied to commercial repowering projects. Since most power plants operate at less than 70 percent utilization, this provision would only partly meet WEPCO-related concerns at most permanent demonstration projects.

Next Steps

All of this discussion points to two key questions. The first is whether the foregoing developments constitute an "adequate" response to the WEPCO issue. Adequacy is inevitably in the eye of the beholder, and the administrative and legislative developments outlined above do move in the right

direction, particularly as regards temporary CCT demonstration projects. Moreover, a good case can be made for reliance on Administrator Reilly's good sense to maintain a sound approach to administration of the new source review provisions of the nonattainment and Prevention of Significant Deterioration programs in the future.

Nonetheless, the Administration's position is that, particularly in light of the special burdens placed on the electric utility industry's coal fired boilers to control acid rain and the importance of flexibility to that program, a broad, clear, generic provision to deal with this issue should be included in the final Clean Air bill. Differences in interpretation among a number of court decisions, uncertainties as to how different decisions will be reconciled, the recent controversy surrounding the application of new source review to modifications of existing utility plants, the vagaries of judicial review of EPA actions, and the long term implications of this policy all point to the conclusion that a clear statement in law would constitute the most effective approach to resolving the new source review issue as it applies to electric utilities.

The second question follows immediately: what sort of broad, generic legislation would the Administration recommend? Let me begin to address this question by making it clear that the Administration views the acid rain program is a supplement to, and not a substitute for, existing Clean Air protections. In particular, local air quality values, measured by attainment of the national ambient air quality standards or, in clean areas, by the prevention of any significant deterioration in air quality, should not be compromised.

We do, however, recognize that the acid rain program will interact with previously existing programs in several important ways. Utilities will be reconfiguring their facilities and dispatch plans to achieve the ambitious sulfur dioxide reductions specified in the acid rain program. The steps taken to meet our ambitious sulfur dioxide reduction goals may greatly increase the number of existing facilities facing NSPS and/or PSD issues over the next 10 years, as compared to a "business as usual scenario". In addition, the acid rain control program imposes a national ceiling on sulfur dioxide emissions, and a national standard for technology on existing utility burners to reduce nitrogen oxide emissions.

Taking account of the need to protect local air quality while at the same time facilitating the ambitious emissions reductions required under the acid rain programs, the Administration supports a broad, generic legislative resolution that has seven basic elements.

(1) The distinction between routine and nonroutine physical and operational changes to electric utility steam electric generating units should be retained. As under current law, routine repair and replacement as well as increased utilization of existing sources that is not accompanied by physical or operational changes would not be considered a "modification" and would thus not trigger new source review. For example, periodic replacement of coal-handling equipment, boiler tubes, and turbine blades is typically considered routine, while replacement of steam and generating turbines is not. To reduce uncertainty, EPA should be instructed to issue, within 18 months of the date of enactment, guidance for use by permitting authorities in determining criteria under which refurbishment projects would be considered routine or nonroutine.

(2) Local air quality values should continue to be protected. Thus, in non-attainment areas, all nonroutine physical or operational changes, including pollution control projects, that result in a net increase in the maximum hourly emission rate of any pollutant would be subject to the review and permitting requirements of part D of Title I. In addition, part D review and permitting requirements would also be triggered by any nonroutine physical or operational change, including pollution control projects, that resulted in a net increase of pollutants in a non-attainment area that would exacerbate the exceedence of air quality standards. The net increase determination would be based on a comparison of before and after emissions across representative periods.

PSD increments or visibility protection limitations promulgated pursuant to Part C must also be protected. Projects that did not increase the hourly emission rate of any pollutant used in establishing the applicable PSD baseline levels for the source (or, for those sources permitted after the establishment of the PSD program, the hourly emission rate specified in the PSD permitting process) would be considered to fall within short-term PSD limits without any further showing, since the short-term PSD baseline and/or increment consumption would have been calculated using that hourly rate. For similar reasons, a project that did not increase annual emissions of a source above the levels used in establishing the baseline or in determining increment consumption would be considered to meet annual PSD requirements for that source without any further showing.

(3) As in the Senate and House Committee bills, temporary CCT projects should be exempted from NSPS, PSD, and NA review provisions. Failure to maintain this exemption would raise significant and unwarranted obstacles to the development of this important technology.

(4) In considering all other nonroutine changes, we would distinguish between "utility pollution control projects" and

other nonroutine changes and apply different tests to each. Any nonroutine physical change in, or change in the method of operation of, an existing steam electric utility generating unit for purposes of reducing emissions at that unit in order to comply with the acid rain title of the Clean Air Act should constitute, for present purposes, a utility pollution control project. This would include, among other changes, gas cofiring. This basic intent standard should be applied to a set of contemporaneous changes, rather than separately to each.

When a plant is idled to permit physical changes aimed at reduction of emissions of sulfur dioxide or nitrogen oxides, it is often economical to make other changes as well. To reduce uncertainty regarding the applicability of new source review requirements to such undertakings, we would specify that contemporaneous physical or operational changes shall be deemed to be part of the utility pollution control project if their value does not exceed 20 percent of the total project value. However, units seeking to take advantage of this provision would be required to meet the NOx reduction limits required by the applicable final rule, if any, issued under Section 407(b) as a part of the total project.

(5) Utility pollution control projects would be evaluated in terms of their impacts on maximum hourly emission rates, following current policy toward NSPS reviews. Thus a utility pollution control project that does not increase maximum hourly emissions of any criteria air pollutant compared to a representative period prior to the project should not be deemed to be a major modification subject to the review and permitting requirements of part C of Title I.

(6) Nonroutine physical or operational changes at existing steam electric generating units other than utility pollution control projects should not be deemed to be major modifications subject to the review and permitting requirements of part C and D of Title I unless they result in a net increase in annual emissions. States would be given the option to allow utilities to reduce costs by employing comparisons of actual emissions involving multiple sources. In cases in which a utility operating company plans to shift generation from other owned units to units affected by the nonroutine physical or operational change and EPA is the permitting authority, the operating company may, for purposes of this section, elect to calculate its actual emissions on a statewide basis. Any State permitting authority may allow actual emissions in both representative periods to be (i) total operating company emissions within the State, (ii) with the agreement of the owners of all other steam electric generating units within the State, total emissions within the state, or (iii) with the agreement of any other States in which the operating company owns steam electric generating units, total operating company emissions.

The calculation of the change in emissions for all projects other than pollution control projects should be based on annual emissions during representative periods before and after the proposed modification. Because emissions increases in nonattainment areas are ruled out by the need to protect local air quality, the same type of comparison would apply to utility pollution control projects in those areas to any emissions of pollutants that would exacerbate the exceedence of air quality standards.

(7) Finally, in cases where a new source review is triggered, we believe the Best Available Control Technology (BACT) standard for nitrogen oxides (NOx) for existing coal-fired boilers should be the standard set forth in section 407 in the Senate bill. That is, for physical or operational changes at an existing steam electric utility unit that require permits under Sections 165 or 173, BACT for NOx should be set at the levels required under section 407 where EPA is the permitting authority. This provision would provide guidance to State permitting authorities, without in any way preempting their authority to set more restrictive standards.

* * * *

Mr. Chairman and members of the Committee, thank you once again for giving me the opportunity to appear before you. I would be please to respond to any questions you might have.

Senator BINGAMAN [presiding]. Thank you very much.

The Chairman has gone to vote, and I need to do the same, and I think this might be a good time for a short break at any rate. So we will take a break and then hear from the other three witnesses in about 10 minutes, as soon as the Chairman returns.

[Recess]

Senator FORD [presiding]. Help us just a little bit. This is not going to be a fun afternoon, I am afraid, as far as moving along on the testimony.

Dick, I understand you finished your testimony. Is that correct?

Mr. SCHMALENSEE. Yes, Mr. Chairman.

Senator FORD. Mr. Blake, would you proceed?

STATEMENT OF FRANCIS S. BLAKE, ATTORNEY, SWIDLER & BERLIN

Mr. BLAKE. My name is Frank Blake. I am an attorney with the law firm of Swidler and Berlin here in town. From 1985 to 1988, I was general counsel at EPA. And based on Dick Schmalensee's testimony, I think he gets an honorary law degree and can join the staff at EPA anytime.

I want to thank you.

Senator FORD. Is that a compliment?

[Laughter.]

Mr. SCHMALENSEE. I am not sure.

Senator FORD. I think you get more compliments by just stating that you are a non-lawyer.

Mr. BLAKE. Mr. Chairman, I want to thank you for all of your efforts on the cofiring issue, and particular, for raising the WEPCO issue for this hearing. It is a particularly complicated issue, as you can tell from the testimony, but it is also a particularly important one. I would like to just, very briefly, outline my testimony on that, and then perhaps give some comments on the administration's proposal here.

First, by way of analogy, I think you can understand the centrality of the WEPCO issue is you think in terms of someone—management of a football team saying to the coach, you have got total flexibility to decide what plays you want to use, but there is one catch. When the ball snaps, we want you to consult with us, and there is only one play we run, and that is in a large way how the WEPCO issue has worked in the past. Under the Clean Air Act——

Senator FORD. And my thought about that is there is a story about Sam don't want that ball.

[Laughter.]

Mr. BLAKE. Under the Clean Air Act, any modification of a stationary source, a major stationary source that results in an increase in pollution has to go through new source review and is subject to new source performance standards. As a result, there is tremendous pressure placed on how you define the modification, how you determine whether there has been an increase in emissions.

The WEPCO decision has added to the uncertainty, at least within the utility industry, on what kinds of changes they can and cannot make before they trigger new source review, and the new source performance standards. Both of those may sound fairly

benign, but the practical result of that is both long delays in the review process, and also a requirement to put on in the case of SO_2 controls, scrubbers. Utilities, therefore, are understandably reluctant to engage in any kind of activity that would risk triggering the new source review requirements.

I would highlight the particular problem that WEPCO raised was the Agency's determination that you would determine whether there was an increase in emissions by comparing the actual emissions beforehand with the potential emissions afterwards. And that would trigger a large number of projects, particularly, if, after the change, the unit was going to be run more than it was before the change. In fact, changes that you would otherwise think of as environmentally benign, were subject to review under WEPCO.

And in particular, Mr. Schmalensee raised the question of whether there was any evidence that the WEPCO decision has been problematic for natural gas cofiring, and the natural gas industry has definitive evidence that it has, both in terms of the particular responses of particular utilities saying, no, we are not interested in cofiring, because it may trigger new source review, and also, more recently down in Texas, the response of one of the pollution control review boards determinations that there was a WEPCO issue.

So we have seen that it is extremely difficult to get new technologies on line with the WEPCO decision still outstanding.

Now, Mr. Schmalensee's testimony set out a number of principles that the administration is proposing to address the problem. I would not begin to give a full response to those now. My reaction to them is, though, that they were moving, certainly, in the right direction, and that they are addressing some of the significant problems that the WEPCO decision has created, particularly for natural gas cofiring. It appears that the administration is recognizing the basic difficulty with the actual to potential comparison, that they are also recognizing a unique role that should be played by pollution control technologies, in terms of, in effect, exempting them from new source review and NSPS requirements.

There are some details and perhaps some general principles that I would argue with in terms of how it could be made, perhaps, a little simpler and more straightforward for people to follow, but at least my initial reaction is that these are changes that are going in the right direction.

Thank you very much, Mr. Chairman.

[The prepared statement of Mr. Blake follows:]

Testimony Before the United States Senate,
Committee on Energy and Natural Resources,
Subcommittee on Energy Research and Development
by
Francis S. Blake

Mr. Chairman and members of the Subcommittee, my name is Frank Blake. I am an attorney in private practice in Washington, D.C., and represent, among others, the American Gas Association. From 1985-1988 I was General Counsel at the U.S. Environmental Protection Agency. I greatly appreciate this opportunity to appear before the Subcommittee and discuss some of the legal issues associated with natural gas co-firing and, in particular, the so-called "WEPCo" issue.

The "WEPCo" issue refers to the set of EPA regulatory interpretations that determine whether a particular physical or operational change at a facility triggers application of new source performance standards (NSPS) and new source review (NSR) under the Clean Air Act. Up until recently, this was an area of the law and the regulations that concerned only those steeped in the details of the Clean Air Act. With the Agency's decision in the Wisconsin Electric Power Company ("WEPCo") case, subsequent decisions by the Agency, and the resulting court litigation, the issue has now become of prominent significance and has major

implications for our country's energy and environmental policy, as well as implications for promising new pollution control approaches, such as natural gas co-firing. The imminent passage of new Clean Air Legislation adds to the importance of this issue. Let me attempt to explain these points briefly.

The Clean Air Act imposes rigorous requirements on major new sources. But -- and this is the critical point for this discussion -- it imposes those same requirements on modifications of existing sources that result in an increase in emissions. The requirements are twofold: (1) the source must meet the NSPS; and (2) it must undergo new source review, which includes extensive air quality modeling, technology standards at least as stringent as NSPS, and, in the case of non-attainment areas, emission offset requirements.

There is an obvious balancing of interests that must occur for this structure to work. On the one hand, if the Agency adopts too inflexible an approach to the modification issue, it will discourage any modifications at existing plants, including changes aimed at plant modernization and improved emissions performance. No existing source would risk the time delays and rigid requirements associated with new source review if it could possibly avoid it. On the other hand, there is clearly a legitimate interest in ensuring that plants not be allowed to undertake major modifications that will increase their potential

emission rates, without undergoing the scrutiny required by the Act.

Until the Agency's WEPCo decision, that balance was maintained or, at least, the issue of actual to potential emission comparisons was not pressed. The Agency focused on modifications that added new units to facilities, increased the original size of the plant or increased the emission rate of the facility. Industry had a fairly clear notion of the kinds of activity that would trigger new source review and could avoid those activities or consciously undertake them.

With WEPCo, however, that balance was disrupted. The Agency stated that, for purposes of new source review, it would determine whether a modification increased emissions by comparing the actual level of emissions prior to the change with the potential level of emissions after the change. This dramatically expanded the reach of new source review and has thrown a broad range of industry practices into doubt. For example, in the past, a unit switching from oil to natural gas would not trigger new source review, since the unit's emission rate would be declining by virtue of the change.[1/] Under the WEPCo reasoning, however, this change could trigger new source review (or force a source to agree to limits on capacity utilization). This would

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1/ Letter from Edward E. Reich, EPA Director, Division of Stationary Source Enforcement, to Amasjit Gill, General Electric (6/24/81).

happen if the unit's prior capacity utilization was low, yielding a low actual emissions base against which the potential emissions at full utilization would be compared. This is not a hypothetical problem. One of the Agency's decisions following WEPCo indicated that an oil to natural gas conversion could trigger new source review.[2/] In other words, one of the offshoots of WEPCo has been to discourage use of cleaner fuels.

In the same vein, the Agency has indicated that a pollution control project could trigger new source review -- this is referred to in more detail in Mr. Maassel's testimony concerning the NIPSCO clean coal demonstration project. More generally, the Agency has created uncertainty over what types of utility repair projects will be considered "routine" (and thus exempted from new source review) and what will not. This raises particularly difficult problems for utilities faced with non-routine outages, where repairing the existing unit may result in triggering NSPS and the scrubber requirement.

The Agency's decisions have had a direct impact on new pollution control approaches, such as natural gas co-firing. Utilities are understandably reluctant in the face of decisions, such as the NIPSCO and Detroit Edison, to embark on any modification -- including those designed to allow the use of

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[2/] Letter from Donald R. Clay, Acting Assistant Administrator for Air and Radiation, to Walter McCarthy, Jr., Detroit Edison (May 8, 1989).

clean burning natural gas -- for fear that the Agency will impose new source review. The end result is that natural gas co-firing, a promising pollution control approach that is consistent with both continued coal use and lower emission rates, is effectively stymied. Many other needed modernization and pollution control activities may be similarly frustrated.

The Agency is in the process of re-evaluating its position on the "actual to potential" comparison, as well as the application of the WEPCo rationale to pollution control projects. The former is necessary in light of the Court of Appeals' decision rejecting the "actual to potential" methodology,[3/] while the latter represents a further response to the NIPSCO project.[4/] But it is not clear what the Agency's new position will be, or how it will address the practical problems that the WEPCo decision has created.

Underlying the maze of new source review regulations and the intricacies of the WEPCo decision rest three key policy decisions that warrant this Committee's and Congress's careful consideration. These decisions have important energy, as well as environmental, implications.

3/ Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

4/ See Letters from David Kee, EPA Region V, to Timothy J. Method, Indiana Dept. of Environmental Management (January 30, 1990).

The first issue involves the importance of certainty versus case-by-case review by EPA. The current trend on the WEPCo issue suggests that the Agency, even as it revises its "actual to potential" approach, will maintain a case-by-case approach to the modification issue. This has the benefit of protecting against any potential environmental abuse since the Agency would review each change, but it is a benefit purchased at a high price. The consequences of new source review are so severe for a utility that unless the rules of the road are clearly laid out and understood, the modification issue will continue to discourage pollution control and modernization efforts. The delay involved in the review process is substantial and can, in and of itself, discourage modifications. The Breaux-Bumpers amendment addressed this issue by leaving case-by-case authority with EPA but, at the same time, creating a presumption against any finding that a modification has occurred in the context of pollution control projects, including natural gas co-firing. Whether this is sufficient will depend heavily on EPA's approach to the statutory presumption.

The second issue is more fundamental: Does Congress want to encourage or discourage the refurbishment and modernization of this country's older facilities? The WEPCo decision was premised on a view that it is better over the long term to force the retirement of those units rather than achieve the benefits of energy efficiency and modernized capacity in the shorter term.

That view has significant energy implications, particularly in light of the substantial burdens that are being placed on the utility industry through the acid rain (and other) provisions of the pending Clean Air Act legislation. Under the pending legislation, existing plants will be required to meet a number of stringent new requirements. Modification of existing sources to improve emissions performance is, in effect, required by the legislation. Given this new legislative mandate, Congress needs to ask -- as this Subcommittee is asking -- whether it makes any sense to penalize modification and modernization activities.

The Administration has heralded the flexibility and cost-effectiveness of this legislation; the natural gas industry, as well as industry in general, has strongly supported those principles; and the cost analyses of the legislation have assumed that industry will have available to it the full range of cost-effective solutions. If that is not to be the case, and if modernization is to be discouraged in the pursuit of longer term reductions, it should be stated clearly, with all of the energy and cost ramifications fully explored. In particular, Congress and the Administration need to address the effect application of WEPCo will have on acid rain compliance costs, on the reliability of electric supply, and on cost-effective new control strategies. This issue is only partially addressed by the existing language in S.1630, which by its terms is limited to certain pollution control projects and not the full range of potential

refurbishment and modernization projects that utilities might want to undertake.

Finally, there are the environmental implications of the modification issue. The WEPCo decision reflects legitimate environmental concerns on EPA's part. The Agency was seeking a method to ensure that actual emissions would not increase significantly after a modification. The "actual to potential" methodology was an excessively cautious approach to achieve that goal. Through its caution, the approach can produce environmentally counterproductive results, as witness the discouragement of pollution control and clean burning fuel projects discussed above. There are alternative methodologies, such as the comparison of "actual to actual" emissions contained now in S.1630, that represent a better balancing of the need for modernization and the purposes of new source review. But the discussion of all the possible variations of "actual to actual," "actual to potential," etc. should not lose sight of the structure and environmental controls contained in the new legislation.

Clearly, WEPCo-type restraints are no longer necessary under the new legislation with respect to SO_2 emissions. There will be no more than 8.9 million tons of SO_2 emitted by utilities, with or without a WEPCo restraint. In this context, WEPCo will only

interfere with the efficient functioning of the SO_2 reduction and trading program contained in S.1630.

The situation with respect to NOx emissions is not as straightforward, but the conclusion is the same. NOx emissions are not capped by the legislation. However, the legislation does require utilities to reduce their NOx emissions from existing units, using as a benchmark for those reductions, the level of control achievable through the use of low NOx burners. If Congress wants to require greater NOx reductions or impose a NOx emissions cap, again, it should do so directly and debate the merits of those measures on their own terms. The weakness of the WEPCo decision is that it approaches those goals indirectly and inefficiently. The environment and the economy will be better served by setting the performance standard and letting all technologies compete to meet that standard. That approach encourages innovation and new options, such as natural gas co-firing; the Agency's original WEPCo approach does the reverse.

In conclusion, this Subcommittee is to be commended for focusing on an issue that is at one and the same time both so technical and so important to the functioning of the Clean Air Act. The principles of flexibility, innovation and cost-effectiveness that should be the foundation for achieving the tough new environmental goals of the pending Clean Air Act

legislation will be severely undermined if the WEPCo issue is not adequately addressed.

Senator FORD. Thank you, Mr. Blake.
Mr. Roberts.

STATEMENT OF WILLIAM J. ROBERTS, LEGISLATIVE DIRECTOR, ENVIRONMENTAL DEFENSE FUND

Mr. ROBERTS. Thank you, Mr. Chairman.

I am William Roberts. I am the legislative director for the Environmental Defense Fund. EDF's staff of economists, scientists and attorneys are dedicated to identifying environmental problems and developing solutions. I am pleased to be here to discuss the recent court of appeals decision in WEPCO and its potential impact on the Clean Air Act Amendments.

Our written statement describes in detail our thoughts on this subject, so I will use this time to summarize those views.

To accurately and fairly evaluate the environmental and economic impact of the WEPCO decision, we believe it is critical to understand the differing air quality impacts from utility sources and the impact the WEPCO decision and its proposed remedies will have on each of these effects.

In our written statement, we review in some detail the requirements of current law and what the court determined in WEPCO. Cutting through this legal morass, we believe there are several points worth stressing.

First, let's not forget that the current Clean Air Act largely exempts existing sources from pollution control requirements. They are exempt whether or not they are a major cause of severe air quality problems. They are exempt whether or not they could achieve substantial emission reductions at lower costs than new sources, and they are exempt whether or not air quality worsens because of their emissions.

Second, the current Clean Air Act contains a narrow exception to this blanket protection for existing facilities. When a facility undertakes a major modification, which results in increased emissions, the facility must comply with the Acts pollution control requirements. Let us be clear that this is a very limited exception. It applies only when a source undergoes a major change. The rules do not apply to routine maintenance, repairs or replacements. In fact, in the WEPCO case itself, the utility was planning to spend $70.5 million to refurbish its plant, and made it clear that its proposed changes did not constitute routine changes.

Everyone knows the difference between changing the oil filter or belts in your car and undertaking a major engine overhaul. The modification rule codifies and applies this distinction. But even a major overhaul of an existing source is not enough to trigger the Act's requirements.

Even if a source undertakes a major, costly and time-consuming renovation, it can still escape pollution control requirements if the changes do not result in a net emissions increase. Even when that source is a major cause of air pollution, it stays out of reach of the Clean Air Acts requirement as long as it does not make the problem worse.

Under this scheme, it is difficult to see how any existing source can seriously complain that the current Clean Air Act treats them

unfairly. Indeed, we believe the Act should be amended to include, rather than to exclude, existing sources. We commend the Senate and the House for moving in this direction by adopting a comprehensive and inclusive Acid Rain Control program, which largely eliminates the distinction between old and new, and instead focuses on what should be the real goal of the Clean Air Act: clean air.

The question before this subcommittee is whether existing sources deserve additional insulation from the Clean Air Act's requirements. The answer to this question must, in our view, depend on the impact of any additional protection on air quality. If additional legislation furthers air quality improvements, we would support that legislation. If additional legislation offered would maintain or worsen air quality, we would be strongly opposed.

For this reason, we believe it is important to divide the kinds of changes a utility might make into those intended to reduce emissions at the source, in compliance with the pending Clean Air Act Amendments, and those having nothing to do with Clean Air Act compliance, or start with changes meant to reduce emissions to comply with the Act.

EDF believes that legitimate questions have been raised about the impact of the modification rule on the pending emissions trading program.

The pending amendments, if enacted, will create an innovative allowance trading system, which will include both new and existing sources. Under the allowance system, utilities will have an incentive to weigh changes on a systemwide basis to determine the most cost effective means to achieve its required reductions. It could, for example, elect to install scrubbers at several plants, run those plants at a higher rate, and reduce operations at its remaining dirty units, or a system could use a combination of scrubber technologies and fuel switching options to achieve the same objectives.

We believe that the confusion and uncertainty surrounding the WEPCO case could impede the integrity of the allowance trading system. In our view, it continues to be an open question whether adding a scrubber or switching fuels could trigger a PSD review.

EPA has recognized the paradox of assuming that increased emissions could occur from changes made specifically to reduce emissions. Indeed, the Agency has specifically reversed this policy in evaluating the clean coal project undertaken by NIPSCO. What remains unclear is whether the Agency will issue an interpretative rule codifying this change in policy.

Because we recognize a need for clarification on this very narrow issue, the Environmental Defense Fund and the National Clean Air Coalition have supported language in the pending House legislation authored by Representative Sharp, which makes it clear that changes made to reduce emissions at the source, in order to comply with the emissions trading program, do not trigger PSD or NSPS review as long as those changes do not increase emissions.

This clarification of WEPCO, like EPA's policy in the NIPSCO, case is limited only to sources who undertake changes to reduce emissions at a utility unit in order to comply with the Clean Air Act. It would not cover sources who, for other reasons, intend to undertake life extension or other major renovations that have nothing to do with compliance under the Acid Rain Program, nor

would it cover sources who make changes not designed to reduce emissions at the source.

Indeed, the already passed Senate legislation contains an amendment by Senators Breaux and Bumpers that is similarly focused only on changes made to reduce emissions. We strongly support the limited focus of this fix. The emissions trading program addresses the air quality concerns of long-range acid deposition from SO_2. It does not address the localized air quality impacts of utility emissions, nor would many of those concerns be addressed under the pending Clean Air Act Amendments. For example, neither the House nor the Senate legislation would adequately address nitrogen oxide emissions from existing sources. The PSD program must be preserved to reduce these emissions.

Utility emissions also raise major concerns in non-attainment areas. Although we want a vibrant allowance trading system, we do not support trades which would adversely affect efforts to achieve attainment in our small, filled cities. We are also concerned that any WEPCO clarification not exempt utility sources from compliance with any particular standard, PSD increment, visibility requirement or air quality related values test for Class I areas under Part C of the Act.

In its current form—the current provisions do not explicitly require compliance with these provisions, and we therefore, support an explicit statement requiring compliance be included in any final legislative language. However, the key point is that the Sharp language and the Breaux/Bumpers amendment will only affect those changes to reduce emissions at the source in order to comply with the Act. In our view, this is a limited, narrow and targeted solution to a limited, narrow and targeted problem.

But some existing sources are asking for more. To borrow some terms from the debate, this subcommittee has been asked to go beyond the simple routine maintenance on the Clean Air Act Amendments to fix a small problem, and instead, it has been asked to make a major modification of current law.

To understand the potentially sweeping nature of these proposed changes, it is important to understand the important role the PSD plays in achieving air quality goals under the Act.

Although the pending Clean Air Act Amendments would set aside the Act's arbitrary distinction between new and existing sources for purposes of the emissions trading program, this comprehensive approach is more often the exception rather than the rule under the Act. By establishing an artificial wall between new and old sources, we are compelled to engage in arcane discussions about what is and is not a modification under the Act, rather than finding the most sensible means to solve an air quality problem.

One of the best examples of this predicament, as we note in our statement, has been the Clean Air Act's field attempt to address visibility degradation in our national parks and wilderness areas. Instead of addressing the severe and growing air quality problem, through straightforward, comprehensive regulations covering new and existing sources, EPA has done nothing. As a result, protection for our parks must wait and wait and wait until an existing source finally undertakes a major modification and triggers required reductions under the PSD program.

Because the Clean Air Act leaves many important air quality problems hanging in the balance, unless and until existing sources undertake a major modification, we have generally supported EPA's long-standing policy of comparing actual or potential emissions to determine whether a change will trigger PSD review. This test is inclusive and will trigger review from many sources who might otherwise go from retrofit to retrofit without achieving needed emissions reductions.

Unfortunately, the issue before this subcommittee is not whether this is the best way to improve air quality, rather the Subcommittee has been asked whether we should make the system worse by postponing even longer the needed emission reductions from existing sources.

We see no reason for tinkering with the current system in order to prolong needed emission reductions. It is true the WEPCO decision left some uncertainties surround the appropriate means to measure net emission increases. But there are available alternatives to EPA's assumption of future round-the-clock operations. EPA can be directed to develop a rebuttable presumption of full scale operations that reflects reasonably achievable maximum operations. The presumed cut-off would be based, not on round-the-clock operation, but may instead, assume a specific high capacity factor.

I, too, have had a chance to quickly look through the administration's proposed remedy to the WEPCO problem, and I would like to quickly comment on my—at least initial cut, on my reaction. In a nutshell, it seems that this proposal represents a major retreat from current law, and responds to a concern which the administration seems to acknowledge is an unproven one. Although Mr. Schmalensee has expressed support for protection of local air quality objectives under the Act, these objectives would seemingly be set aside if the proposal were adopted.

For example, an area of great concern, as I noted earlier in the Act, is deteriorating visibility in our national parks and wilderness areas due to manmade pollution. Assume an existing utility is a major cause of visibility degradation at a national park. Under current law, a life extension project would trigger pollution controls to reduce those harmful emissions, but under this proposal by the administration, a utility causing this problem could escape all review by obtaining offsets from sources hundreds of miles away, either in the same State or even in other States. Allowing offsets from States to avoid pollution controls clearly abandons the local air quality goals in the Clean Air Act.

In addition, the administration proposes going beyond the concerns of WEPCO and proposes to rewrite the rules for sources who do trigger new source review, even under the administration's unduly broad definition. It proposes, without explanation, to dramatically weaken best available control technology standards as those standards apply to NO_x emissions. By relying on the weak standards of Section 407, which do not reflect the best available control technology, we are essentially weakening NO_x standards.

Finally, and this is on a first review, it appears as though the administration is proposing that when you do apply scrubber technologies or pollution control equipment, we are now called upon to

measure, not whether there is going to be an actual increase in emissions following that change, but whether there will be an increase in the rate of emissions. Once again, if the goal here, as the administration seems to suggest, is the preserve protection of local air quality values, we are setting that goal aside, focusing only on rates now, rather than absolute increases in emissions.

That concludes my statement, and I am prepared to answer questions.

[The prepared statement of Mr. Roberts follows:]

STATEMENT OF WILLIAM J. ROBERTS
LEGISLATIVE DIRECTOR, ENVIRONMENTAL DEFENSE FUND
BEFORE THE SUBCOMMITTEE ON ENERGY RESEARCH AND DEVELOPMENT
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

HEARING ON WEPCO v. EPA
May 8, 1990

Mr. Chairman, Members of the Committee, I am William J. Roberts, legislative director of the Environmental Defense Fund, a national non-profit organization with over 150,000 members. EDF's staff of economists, scientists and attorneys is dedicated to identifying environmental problems and developing solutions.

I am pleased to be here today to discuss the the recent court of appeals decision in Wisconsin Electric Power Co. v. EPA and its potential impact on the Clean Air Act Amendments of 1990.

The WEPCO decision has touched on several important issues affecting the air quality impacts of utility emissions and the costs of controlling those emissions. First, the decision has raised concerns about the implementation of the emissions trading provisions in the Clean Air Act Amendments. As a result of these concerns, a number of legislative proposals have been offered to remedy the adverse impact the decision may have on differing policies in the Clean Air Act Amendments.

Second, the WEPCO decision and its legislative "fixes" have also implicated other provisions of the Clean Air Act governing nitrogen oxide emissions, nonattainment, visibility degradation, protection of national parks and wilderness and other effects of utility sources on air quality.

To accurately and fairly evaluate the environmental and economic impact of the WEPCO decision on Clean Air Act policies, we believe it is critical to separate the differing air quality impacts from utility sources and the impact the WEPCO decision and its proposed remedies will have on each of these environmental effects.

However, before tackling these diverse environmental impacts, we believe it is worth reviewing the holding and circumstances surrounding the WEPCO decision. The level of misunderstanding and confusion over WEPCO requires a clear explanation of the problem, before we evaluate solutions.

WHAT THE CLEAN AIR ACT CURRENTLY REQUIRES

1. The Clean Air Act and Existing Sources

Under the Clean Air Act, existing sources outside of nonattainment areas are largely exempt from the Act's requirements. Generally speaking, only sources which are new or undergo modifications are required to comply with certain technology-based standards and other restrictions under Section 111, Section 165, and Section 173 of the Act.

Indeed, it has been this weakness in the Act -- the inability to incorporate existing sources into comprehensive emissions reduction programs -- which has compelled the development of separate acid rain legislation to achieve the substantial emissions reductions caused by existing, as well as, new sources of pollution. It is also the reason Congress enacted separate legislation in 1977 directing EPA to develop a comprehensive solution to visibility degradation in our national parks covering both new and existing sources.

Unfortunately, by focusing almost exclusively on new emissions sources, the Clean Air Act tilts away from a more comprehensive and cost-effective approach to air pollution problems focusing on all sources of emissions -- new and old.

2. "Modified" Sources

However, the Act does not protect all existing sources from the Act's requirements. If an existing source undertakes a physical or operational change which results in an increase in its emission rate or which results in a significant increase in total emissions within an attainment area, the Act triggers a review to insure that the emissions increase will not violate national ambient air quality standards, exceed the maximum allowable increases under the PSD program, or violate air quality related values established for our national parks. It also requires that the modified unit install the best available control technology. In short, these "modified" units are treated like new units for purposes of the Act.

Although this definition of a "modification" is fairly broad, EPA has further defined the term "modification" by carving out some common-sense exceptions for activities considered "routine," including regular maintenance, repairs, or replacements. Exceptions also are provided for activities which result in an increase in a unit's production rate or an increase

in a unit's hours of operation.

WHAT THE COURT SAID IN WEPCO

In the WEPCO case, the utility company challenged EPA's determination that a so-called "life extension" project at one of its plants was a legal "modification" under both the NSPS provisions of the Act and under the Act's program to Prevent Significant Deterioration (PSD) in attainment areas and therefore required NSPS and PSD review.

1. Routine vs. Non-routine Changes.

In assessing the utility's claim, the court first agreed with EPA's interpretation that the proposed project did not qualify under EPA's regulations as a routine change. Indeed, the the utility had admitted in its application for the $70.5 million renovation that items "falling into the category of repetitive maintenance that are normally performed during scheduled equipment outages are not included in this application."

We believe this is an important point. Although some have argued that the WEPCO decision would trigger NSPS and PSD review for minor maintenance, there is nothing in EPA's regulations or in the court's decision to justify that concern. As we read both the regulations and the court's decision, routine maintenance, repairs, or replacements do not trigger either NSPS or PSD review.

2. Measuring Emissions Increases

Having concluded that the utility's plan called for a non-routine physical change, the court turned to EPA's assertion that the change would result in an increase in emissions -- the other prong in the test to require NSPS and PSD review. Here the court had to face two separate tests for emissions increases. Under NSPS, EPA was required to assess whether there would be an increase in the emission rate as a result of the physical change. Under PSD, EPA was required to determine whether there would be an absolute increase in emissions from the change.

In assessing emissions rates for purposes of NSPS review, the court agreed with EPA's decision to use emissions rates during representative performance of the plant before and after the change. This methodology would attempt to measure any actual increases in emission rates from the change. The court upheld EPA's conclusion that WEPCO's emissions rate would increase.

From a policy standpoint, measuring only emissions rates does nothing to prevent actual emissions increases. Indeed, by ignoring absolute emissions increases, existing sources could

substantially worsen air quality without triggering NSPS review.

Although the court accepted EPA's methodology for NSPS review, it rejected EPA's method for measuring the change in absolute emissions required by the PSD program. EPA had compared actual emissions from the plant for a two year period preceding the change with the maximum potential emissions of the plant after the change. Although the utility could have agreed to an enforceable emissions limit to avoid application of this "potential emissions test," it elected not to do so. As a result, EPA assumed for purposes of its evaluation that the plant would operate after the change at maximum potential capacity, i.e, 24 hours a day, 365 days a year.

The court ruled that this interpretation by EPA was not supported by either the Clean Air Act or the agency's own regulations. Although the court considered the "potential emissions test" to be appropriate in the case of a new unit with no history of operating practice, the court cited precedents for the proposition that if a source is an established operation, a "more realistic assessment of its impact on ambient air quality" is required. Alabama Power Co. v. Costle, 636 F.2d 323, 379 (D.C. Cir. 1979).

3. Using Alternative Fuels

Finally, the court ruled on the important issue of fuel switching. The utility had argued that it could avoid NSPS review through an enforceable agreement to switch from high sulfur to low sulfur coal to ensure that its emissions rate would not increase. EPA rejected this plan on the grounds that the current Clean Air Act favors the implementation of pollution control technologies, rather than alternative fuels and such alternative fuels could not, therefore, be used to comply with the Act. The court, referring to legislative history from the 1977 amendments to the Clean Air Act, agreed with EPA's interpretation that Congress had rejected fuel switching as a means to avoid triggering NSPS review.

From an environmental standpoint, we believe there is no basis for excluding the use of alternative fuels from consideration under the Act. We believe the goal of the Clean Air Act should be to achieve clean air, and we support the least cost, most effective means to achieve that goal. If the use of low sulfur coal or natural gas would achieve the same environmental goal at lower cost, these alternative fuels should be encouraged, not discouraged by the Clean Air Act.

This lengthy description of WEPCO is important to dispell some myths and misrepresentations being circulated about the decision. Although some have characterized WEPCO as requiring

the application of new source performance standards or best available control technologies for minor or routine physical

changes in a utility unit, these characterizations are flatly wrong. In addition, even non-routine changes that do not increase a unit's emissions rate or significantly increase absolute emissions will not trigger NSPS or PSD review.

WHAT IMPACT WEPCO HAS ON EMISSIONS TRADING

Despite the limited scope of this decision, we still believe it is necessary to assess its impact on the Clean Air Act Amendments because those amendments, if enacted, would require pollution control from existing electric utility sources. Therefore, we believe it is important to ensure that our efforts to reduce emissions from existing sources under the Clean Air Act Amendments of 1990 are not undercut by the WEPCO decision.

This evaluation is critical because the pending Amendments will incorporate an innovative allowance trading system which is dependent on flexible investment decision-making by affected sources. To the extent the WEPCO decision distorts or eliminates this flexibility, the environmental goals of the trading system may not be achieved.

At the same time, we also believe it is important to limit any legislative "fix" resulting from the WEPCO decision only to those circumstances which would interfere with effective implementation of emissions trading. The pending Clean Air Act Amendments do not rectify all of the adverse air quality consequences of existing utility sources. For this reason, it is important to preserve the existing mechanisms of the Clean Air Act to address the environmental effects of emissions increases from existing sources. EDF strongly supports provisions in both the House and Senate bills that make it clear that compliance with the acid rain program does not exempt compliance with other programs in the Act.

Of greatest concern is the impact WEPCO may have on the allowance trading provisions of the pending Amendments. Specifically, the Clean Air Act Amendments, as passed by the Senate and the House Energy and Commerce Committee, contain an innovative emissions trading program to achieve significant reductions in SO2 emissions from existing electric utility units at significantly reduced costs.

1. Benefits of Emissions Trading

EDF strongly supports the use of an allowance trading system to achieve significant SO2 emissions reductions. If it is allowed to work smoothly and efficiently, the allowance trading system can achieve substantial environmental benefits at lower cost. Most analyses indicate up to 50 percent in cost savings by using an allowance trading system compared with other methods of emissions reductions.

Under the allowance system, affected utility units have an incentive to lower emissions beyond those required by law in order to profit from the sale or banking of unused allowances. The greater the demand for allowances, the greater the incentive for affected units to reduce emissions below the legal limit.

In addition, utility systems have an incentive to weigh changes on a system-wide basis to determine the most cost effective means to achieve its required reductions. It could, for example, elect to install scrubbers at several plants, run those plants at a higher rate, and reduce operations at its remaining "dirty" units. Or, a system could use a combination of scrubber technologies and fuel switching decisions to achieve the same objectives. The key to this program is preserving the flexibility of the utility system to work out the best alternative to achieve the required reductions.

However, the viability of the allowance trading system is dependent largely on unencumbered market investment decisions. To the extent the marketplace is clouded with uncertainties or incentives that hamper cost-effective investment decisions, the goal of least cost emissions reductions may not be achieved. In our view, preserving flexible investment decisions is critical to achieving the goals of the trading program.

Removing this flexibility could mean not only higher costs for emissions reductions, but could discourage the use of conservation and energy efficiency programs and the development of innovative technologies to achieve excess emissions reductions.

2. WEPCO Could Impede Emissions Trading

We believe that the confusion and uncertainty surrounding the WEPCO decision and the policy articulated by EPA in that case could impede the integrity of the allowance trading system. As noted above, a utility system could elect to add a scrubber to one unit that could trigger PSD review because the "potential" emissions after installation of the scrubber (i.e., 24-hour, 365 days per year operation) could exceed actual emissions preceding the change.

In addition, a utility could elect to retrofit portions of a unit to permit the use of alternative fuels, such as low sulfur coal or natural gas. But, because EPA currently ignores changes in fuel for purposes of comparing emissions rates, NSPS review could be triggered against that unit.

Obviously, broad application of WEPCO policies could undermine the flexibility utility systems need to reduce emissions in a cost effective manner under the pending amendments.

As a result, the Environmental Defense Fund and the National Clean Air Coalition have supported language in pending House legislation authored by Representative Sharp which makes it clear that "no physical change in, or change in the method in operation of, a source for purposes of reducing emissions in order to comply with [the acid rain title] shall be treated as a modification [under NSPS or PSD] if such change does not increase the potential emissions of any air pollutant from such source above the potential emissions prior to the change."

3. A WEPCO "Fix" for Emissions Trading Must Be Limited to Changes Required by Emissions Trading

This clarification of WEPCO is limited only to sources who undertake changes to reduce emissions at a utility unit in order to comply with the acid rain provisions. It would not cover sources who, for other reasons, intend to undertake "life extension" or other major renovations that have nothing to do with compliance under the acid rain program. Nor would it cover sources who make changes not designed to reduce emissions at the source. NSPS or PSD review for these changes would be governed by current law.

We strongly support these limitations and consider them necessary ingredients of any WEPCO "fix" for emissions trading. Reaching beyond the trading and emission reduction provisions of the acid rain title could, in a backhanded way, undermine the important air quality objectives of other provisions in the Clean Air Act such as visibility protection, nonattainment protection, and other air quality programs.

For example, neither the House nor Senate legislation would adequately address nitrogen oxide (NOx) emissions from existing sources. Both bills call for certain emissions limits designed to reduce NOx emissions. However, both proposals largely exempt cyclone boilers, a major source of NOx emissions, from mandatory emission reduction requirements. In addition, neither bill goes far enough in reducing and capping nationwide NOx emissions.

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Neither proposal caps NOx emissions, and, indeed, the House bill would allow NOx emissions to increase until 2000 before any reductions would be required. For these reasons, we must be able to rely on the trigger provisions of NSPS and PSD, including a review process, to achieve reductions in NOx emissions from these sources.

We have a similar concern with the localized effects of SO2 and NOx emissions in nonattainment areas. Although we want a vibrant allowance trading system, we do not support trades which would adversely effect efforts to achieve attainment in our smog-filled cities. We have opposed WEPCO clarifications for emissions trading that would extend to nonattainment areas.

We are concerned that any WEPCO clarification not exempt utility sources from compliance with any PSD increment or air quality related values test for Class I areas under Part C of the Act. Compliance with these provisions is needed to ensure that our attainment areas do not slip into nonattainment. In its current form, the Sharp language does not explicitly require compliance with PSD increments or air quality related values and we therefore urge that an explicit statement requiring compliance, including procedures to assure compliance, be included in any final legislative language.

Finally, we are concerned that any applicable visibility protection requirements continue to apply. As noted earlier, current law requires EPA to develop regulations to address the environmental impact of visibility impairment on Class I parks and wilderness areas. Once again, the Sharp language should be modified to require a review to ensure continued compliance with these requirements.

In short, the process of PSD and NSPS review must continue to be available in those circumstances where localized air quality impacts are not adequately addressed elsewhere in the Act. PSD and NSPS review are admittedly blunt instruments to mitigate emissions increases from existing sources. And, although we would strongly urge Congress to pursue other, more comprehensive strategies to achieve emissions reductions, as it has done with the pending acid rain provisions, we believe these tools must remain available to achieve emissions reductions from existing sources.

4. Measuring Emissions Increases

Concerns have also been raised about the method used in the Sharp provision to measure net emissions increases. The Sharp provision requires that emissions be compared using a potential-to-potential test. In other words, the provision requires EPA to compare potential emissions before the change

with potential emissions afterwords, rather than actual emissions before the change with potential emissions afterwords. This methodology offers the benefit of a straightforward, simple test to gauge a net increase in emissions. The predictability of the test enables utility owners to easily assess whether their investment decisions might trigger NSPS and PSD requirements.

Although EDF has expressed support for this provision, we recognize that the potential-to-potential test has its problems. Although the provision ensures that comparisons are made from a common assumption -- potential operation, there are legitimate concerns that such a comparison may not realistically reflect the impact of the change on actual emissions. The analyses may suffer from the same hypothetical pitfalls the court criticized in the WEPCO decision. EPA should be able to implement the potential-to-potential test in a more rational way by relying on rebuttable presumptions concerning baseline operations and other factors to ensure that the comparison is more realistic.

In addition, any shortcomings in the emissions test should be largely offset by the requirement that the change be undertaken to reduce emissions at the source. It is difficult to conceive of changes designed to reduce emissions at the source, which actually lead to increased emissions.

This paradoxical outcome might occur if a utility decides to install a scrubber on certain units and subsequently increases operation of those units in order to decrease operation at "dirty" units. Although some may interpret the result of these decisions as a net emissions increase at the scrubbed units, we read EPA's regulations as exempting changes in the hours of operation from the definition of a "modification." In our view, this is a sensible exclusion and should apply to the Sharp amendment as well.

WHAT IMPACT WEPCO HAS ON THE PSD PROGRAM

Although we support the narrow focus of the Sharp language on changes made only to reduce emissions in compliance with the emissions trading program, we recognize that the WEPCO decision and Sharp "fix" leave in doubt the trigger for PSD review for other types of changes. The court has rejected EPA's longstanding actual-to-potential emissions test as unrealistic and has directed the agency to develop another methodology.

Because the Sharp language will only affect those changes relating to emissions trading, we must still examine the impact of WEPCO on changes which are not meant to reduce emissions. Before tackling this question, we believe it is important to understand the important role the PSD program plays in achieving air quality goals under the Act.

1. The Reluctant Role of PSD in Improving Air Quality

As we have noted at several points in this statement, we believe that the current Clean Air Act inappropriately excludes existing sources from emission reduction requirements. By essentially grandfathering existing sources, the Act places the burden for solving even severe air quality problems on the shoulders of new sources or sources undergoing major renovations, even though existing sources could, in many cases, use relatively low cost measures to substantially improve air quality problems.

Although the pending Clean Air Act Amendments would set aside the Act's arbitrary distinction between new and existing sources for purposes of the emissions trading program, this comprehensive approach is more often the exception, rather than the rule, under the Act. By establishing an artificial wall between new and old sources, we are compelled to engage in arcane discussions about what is and what isn't a "modification" under the Act, rather than finding the most sensible means to solve an air quality problem.

One of the best examples of this predicament has been the Clean Air Act's failed attempt to address visibility degradation in our national parks and wilderness areas. Visibility degradation has been a severe air quality problem for many years, particularly in the West. The National Park Service estimates that the scenic vistas in the parks are affected by man-made pollution over 90 percent of the time. The Grand Canyon, which has been extensively studied, can present a breathtaking view of up to 200 miles on a clear day. But, on a polluted day, one can barely see the other side of the Canyon, only 10 miles away. Furthermore, the problem is expected to worsen under the pending Clean Air Act Amendments because the emissions trading provisions contain a loophole allowing potentially large increases in emissions in the West.

To solve this problem, Congress included a requirement in the 1977 Clean Air Act Amendments calling on EPA to develop a set of comprehensive regulations, covering both new and existing sources, to reduce and prevent the manmade pollution causing visibility degradation. EPA has failed to promulgate these regulations.

EPA's failure to act has not made the problem go away. In fact, the National Park Service has recently reported that potential increases in SO2 emissions, based on EPA's analysis of the Senate emissions trading program, would cause a two- to three-fold decrease in visibility in the Grand Canyon and a five-fold decrease in Glacier National Park, Montana, over the next two decades. Without a sensible program for park protection

developed by EPA, those concerned about these national treasures must reluctantly rely on the remaining tools in the Act -- including PSD review.

Fortunately, in the case of park visibility, there is another path. The National Clean Air Coalition and the Environmental Defense Fund have expressed their strong support for an amendment to the Clean Air Act Amendments offered by Representative Wyden that would require EPA to develop the regulations it should have developed 13 years ago. The Wyden Amendment would, at long last, address visibility degradation in a comprehensive, rather than piecemeal, way.

But, if the amendment is not accepted either in the House or by the Senate in conference, we will be compelled to rely on the existing PSD program to trigger emissions reductions when and if a utility decides to retrofit its plant. Although this is a cumbersome and costly way to achieve emissions reductions, it must be preserved if no other method of achieving reductions is available.

2. EPA's Treatment of Modifications

Because the Clean Air Act leaves many important air quality problems hanging in the balance unless and until existing sources undertake a major modification, we have generally supported EPA's longstanding policy of comparing actual-to-potential emissions to determine whether a change will trigger PSD review. This test is inclusive and will trigger review for many sources who might otherwise go from retrofit to retrofit without achieving needed emissions reductions.

Given the Act's current favoritism toward existing sources, many utilities have charged that EPA's policy is unfair and undercuts the Act's protection for existing sources. We disagree.

As the court in WEPCO noted, EPA's policy does not apply to routine maintenance, repairs or replacements. Nor does it apply to changes in the hours of operation. EPA's policy only covers major renovations which, as the legislative history of the Act makes clear, occur at an appropriate time to achieve emissions reductions. In addition, for our purposes, we are considering only changes which are not undertaken to achieve SO2 emissions reductions. Changes undertaken to reduce emissions, as we have noted, deserve separate treatment under the emissions trading program.

3. Measuring Emissions Increases

The real issue, it seems, is whether EPA has used a sensible approach to measuring net emissions increases. We agree with the court in WEPCO that there is an incongruity in comparing actual emissions before a change to potential emissions following the change, but we believe that the court's real concern was with the method EPA used to measure potential emissions after the change. Clearly, the court thought EPA's assumption of continuous, round-the-clock operation after a change was unjustified. Thus, we read the court's opinion as holding that the actual-to-potential test is appropriate, so long as EPA uses a more sensible measurement of future potential emissions.

What is the most sensible way to measure future potential emissions? As we noted in discussing the Sharp proposal, EPA can develop a rebuttable presumption of full scale operations that reflects reasonably achievable maximum operations. The presumed cutoff would not be based on round-the-clock operation but may, instead, assume a specific, high capacity factor. This approach preserves the certainty and simplicity of the potential test, but ties it closer to real plant operations.

The House Energy and Commerce Committee has proposed a different solution to address the court's concern in WEPCO. The Committee approved an amendment by Representatives Tauzin and Bruce which says that a change shall not be considered a PSD modification if the utility owner submits sufficient information to demonstrate that the change will not result in a net increase in actual emissions for any regulated pollutant; in other words, EPA must conduct an actual-to-actual emissions comparison. This amendment attempts to track the direction the court was taking in WEPCO in calling for a realistic assessment of emissions changes.

But, measuring future actual emissions, like measuring future potential emissions, has its problems. Measuring future, actual emissions requires EPA to rely on the representations, speculation, and guesstimates of the utility owner. Without a binding agreement from the utility owner, there is no assurance that the utility owner's predictions will pan out. Obviously, this approach is subject to substantial gaming from utility owners who have a compelling incentive to downplay expected emissions changes. And, without reliable information from the utility owner, EPA will itself end up speculating and guesstimating.

We understand the need for a more reliable measure of potential future emissions, but such a test must be an objective one capable of easy enforcement and application. We are unconvinced that predicting actual emissions for a particular source, without a commitment from the source to abide by its

prediction, can be effectively implemented or enforced. Instead, we believe EPA can and should develop a benchmark standard for potential operations that more closely reflects real plant operations.

CONCLUSION

In conclusion, we want to express our support for a limited legislative "fix" to the WEPCO decision to ensure that utility systems have the flexibility they need to implement in a cost effective manner the requirements of the pending emissions trading program. This "fix" must satisfy at least five requirements: (1) it must be limited to changes undertaken to reduce SO2 emissions, (2) such changes must be made for purposes of complying with the emissions reduction requirements of the acid rain provisions, (3) any unit which satisfies the provision must still demonstrate that it will comply with applicable national ambient air quality standards, PSD increments, air quality related values in Class I areas and visibility regulations, (4) the clarification must use a clearly understood and consistently applied methodology to determine net emissions increases, and (5) it must make clear that only increases directly caused by a physical change should be considered in making emissions comparisons.

For changes which do not reduce emissions in order to comply with the emissions trading program, we continue to support EPA's current policy measuring actual-to-potential emissions to determine whether such changes will cause a net emissions increase. We recognize that EPA's current method for measuring future, potential emissions is unrealistic, but we believe EPA can be directed to develop a more sensible and certain measure of such emissions and preserve the policy of assessing changes against potential emissions increases.

In our view, it does no good to establish an emissions trading program premised on flexible decision-making and planning, only to have other provisions of the Act hamstring that planning process. However, it is possible to unleash the emissions trading system without discarding all of the tools in the Clean Air Act to deal with air quality. By following the suggestions outlined in this statement, we believe it is possible to craft a provision to achieve both goals.

ENVIRONMENTAL DEFENSE FUND

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May 7, 1990

Honorable Wendell Ford, Chairman
Subcommittee on Energy Research and Development
Committee on Energy and Natural Resources
United States Senate
SD-364
Washington, D.C. 20510

Dear Chairman Ford:

The written statement presented to your Subcommittee from the Environmental Defense Fund contains a typographical error that we wish to correct for members of the Subcommittee.

On page 7 of the statement, we quote a provision authored by Representative Sharp that inadvertently excludes an important phrase in the Sharp provision. The provision should read:

> "No physical change in, or change in the method in operation of, a source for purposes of reduction emissions from such source in order to comply with this title shall be treated as a modification for purposes of section 111 or part C of title I of this Act if such change does not increase the potential emissions of any air pollutant from such source above the potential emissions prior to the change."

The underscored language was mistakenly left out of EDF's written statement and, as we note elsewhere in our testimony, this phrase is a critical limitation on the Sharp provision. As we stress on page 7 of our statement, the Sharp provision does not cover "sources who make changes not designed to reduce emissions at the source." Only measures taken to reduce emissions at a particular source would be subject to the net emissions test in the Sharp provision.

Because this clarification is a critical component of our statement, we request that this letter be included with our statement in the hearing record.

Sincerely,

William J. Roberts
Legislative Director

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Senator FORD. Thank you, Mr. Roberts.
Mr. Maassel.

STATEMENT OF MARK T. MAASSEL, MANAGER, ENVIRONMENTAL PROGRAMS, NORTHERN INDIANA PUBLIC SERVICE CO.

Mr. MAASSEL. Thank you for allowing me the opportunity to present views on this very significant environmental, energy and natural resources issue.

This afternoon, I would like to focus on two facets of the WEPCO policy. First, I would like to address the current pending Clean Air Act legislation in the Senate and in the House of Representatives, and the potential limitations contained in their dealing with the WEPCO issue.

Second, I would like to briefly outline the long-term effects of WEPCO on electric utilities' ability to provide adequate, cost effective service to our customers, even if the limitations on WEPCO, included in the proposed Clean Air Act Amendments, are enacted.

Turning first to the proposed Clean Air Act legislation, both the House and the Senate have addressed this issue. However, they have addressed only a limited portion of the WEPCO policy. They simply address pollution-reducing projects and clean coal technology projects.

In reviewing the two legislative proposals, it is apparent that the Senate version does not convey as clear a message to the EPA as the House version. For example, the Senate language is incorporated into Section 415, which deals with clean coal technology programs. As such, the effectiveness of that language might be weakened. By contrast, the House of Representatives, in Representative Sharp's proposal, has specifically delineated the WEPCO issues for a non-clean coal technology power plant as a separate and distinct section.

Additionally, the Senate language addresses only the PSD aspects of the WEPCO policy, while the House addresses both PSD and NSP. As a result, the House provision, by Representative Sharp, is preferable to the Senate provision.

A clear expression of congressional intent and guidance on this issue is significant and necessary. I would like to relay an example from my own company's experience, which has been alluded to as an illustration of the need for this congressional action.

Northern Indiana Public Service Company is a host site for a round two Department of Energy clean coal technology project. The project involves the construction and operation of a full-sized, advanced flue gas desulfurization system. This FTD will be operated as a demonstration project for 3 years with the Department of Energy co-funding construction and operation during that demonstration period. At the conclusion of the demonstration period, the FTD will begin commercial operation for a 17-year period. Northern Indiana did request EPA clarification of the NSPS and PSD issues related to that project.

The EPA issued a letter dated July 14, 1989, which indicated that we might be subject to NSPS or PSD review, if that project operated for over 5 years. We requested further clarification, in light of the fact that the proposed project was the implementation

and installation of a device intended to remove over 90 percent of the potential sulfur dioxide emissions, seven and a half years prior to the second phase requirements of the Clean Air Act legislation.

EPA's verbal analysis initially indicated that, in fact, PSD would apply. We continued the discussions with the Agency. The discussions led to letters dated January 5, January 30, and March 8, 1990. In those letters, EPA did establish that NSPS and PSD would not apply to that project. However, they announced their intent to issue an interpretative ruling, further clarifying the applicability of NSPS and PSD in situations where utilities were reducing emissions.

Although promised since early 1990, no such ruling has been issued.

This scenario of events illustrates the need for congressional direction and action. However, as I previously noted, the language in the pending Clean Air Act legislation does not address all WEPCO issues. EPA has totally ignored the cost impacts of its WEPCO decision.

Further, no assessment of the impact of reliability of electric supply has been conducted. Many forecasters are predicting that electric energy shortages will occur in the 1990s in many parts of America.

This situation will be heightened by EPA's WEPCO policy. Through 1995, estimates show that the WEPCO policy could affect the reliability of the supply of electricity in regions where as many as 138 million people live. The Agency's interpretation caused declining reliability by restricting cost effective maintenance programs, causing operations at progressively lower capacity levels and forcing early retirements of plants. These effects could reduce installed capacity by 34 gigawatts by 1995, which is almost half of the new capacity planned for customers, which will be needed simply to meet low growth in the future. EPA's WEPCO policy also has adverse environmental implications.

Since the United States Congress is deliberating the Clean Air Act legislation this year, it has worked to strike a balance between the cost and the benefit of increased environmental control of air emissions. The legislation addresses SO_2, NO_x, and particulate emissions from utility power plants. After crafting such legislation, EPA could significantly alter the balance struck in the legislation by application of the WEPCO policy. Thus, while Congress is preparing to chart a course for the country's environment and energy future, EPA, by application of existing law, can dramatically sway that direction, substantially increasing costs and reducing electric system reliability.

If I may, Mr. Chairman, I would like to comment on Mr. Schmalensee's testimony today, as well. Although we have not, of course, had a chance to look at it in any detail, I have to admit that I am very encouraged to see the administration beginning to take an active role in the WEPCO debate. There are many good features contained in the proposal today, although it also raises many questions. We are concerned, for example, that increases in the use of a particular power plant, resulting simply from increased electric demand from our customers wanting electricity, might still, somehow, trigger the WEPCO reviews underneath of the proposal that

was introduced today. So, while I am encouraged that there has been definite progress in this area, I believe that we have a ways to go. I believe that the uncertainty surrounding the WEPCO policy remains, even after today. Thank you very much.

[The prepared statement of Mr. Maassel follows:]

TESTIMONY BEFORE THE UNITED STATES SENATE
SUBCOMMITTEE ON ENERGY RESEARCH AND DEVELOPMENT
S. 1848 NATURAL GAS COFIRING PROMOTION ACT OF 1989

by
Mark T. Maassel
Northern Indiana Public Service Company

May 8, 1990

Thank you for allowing me the opportunity to present the views of an electric and gas utility company on a very significant environmental, energy and natural resources issue. Beginning in fall 1988, the United States Environmental Protection Agency (EPA) began to issue a series of decisions which found that certain alterations of power plants, both physical and operational, were modifications and major modifications which triggered the application of New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) review pursuant to Section 111 and parts C and D of the Clean Air Act. These decisions charted a new direction in the application of existing regulations. These EPA decisions applying EPA's new NSPS and PSD policy are collectively referred to as WEPCO.

EPA first began to announce its WEPCO policy in the Wisconsin Electric Power Company Port Washington decision. Port Washington involved the replacement of certain large boiler components, air pre-heaters and other equipment in the five small power plants located at that site. EPA determined that since the replacement was "costly" and "non-routine", NSPS applied. In making its decision, EPA defined "costly" as an expenditure of over 5% of the original cost of the steam generating

units. Since EPA did not even account for inflation, 5% of the cost of a steam generating unit built many years ago is a remarkably small sum of money by today's standards. EPA also determined that PSD applied. Their PSD determination was based on a comparison of actual operating experiences on admittedly aged plants versus full load operation for 365 days per year, 24 hours per day. It is difficult to believe that many plants would be able to pass this test since even the newest, best maintained plants achieve full load operation no more than 80 percent of the year.

The U. S. Court of Appeals for the Seventh Circuit upheld EPA on appeal of the Port Washington plant decision on the NSPS issue but held that the PSD review requirement, although statutorily valid, had never been implemented by a proper rulemaking procedure subject to notice and comment. EPA has nonetheless gone on its way to expand the current policy, simply limiting the Seventh Circuit's decision. In addition, EPA has applied its WEPCO logic in oil to natural gas fuel switches and clean coal technology projects.

As I mentioned previously, EPA's WEPCO policy marked a change in the application of existing regulations. Prior to the fall 1988, New Source Review was applied to (1) an increase in emission rate above design levels; (2) enlargement of an existing unit and (3) construction of new units. EPA did not attempt to compare past actual emissions with future potential emissions if a source had been in operation for some time.[1] As recently as 1988, the Agency did not apply the PSD modification rule when an oil company reactivated two petrochemical plants that had been shut down for a decade.[2] Prior to 1988, under EPA applicability decisions,

facilities could switch fuels from oil to gas without worrying whether new source review would be triggered.[3]

WEPCO has fundamentally changed these understandings. The Agency has created an entirely new regulatory regime that is not clearly defined nor understood by this nation's electric utility industry. EPA is reluctant to communicate its view of the law with respect to life extension and the modification rules. John Calcagni, director of EPA's Air Quality Management Division, was recently quoted in Power Engineering as stating that the Agency has no plans "to publish something about its application of new-source emission standards to modifications of old plants" because anything in writing "could be dissected by attorneys in search of loopholes." As a result, utilities cannot be certain how broad the sweep of the EPA policy will be and thus cannot fully predict the consequences of altering any physical aspect of a power plant, or its operations. However, every signal that we have noted shows that EPA is moving expansively to require New Source Review for as many alterations, whether physical or operational, as possible.

With this general background, I would like to focus on two facets of the WEPCO policy. First, I would like to address the current pending Clean Air Act legislation in the Senate and in the House of Representatives and the potential limitation of WEPCO in those bills. Secondly, I would like to briefly outline the long term effects of WEPCO on electric utilities' ability to provide adequate cost effective electric energy to their customers, even if the limitations on WEPCO included in the proposed Clean Air Act Amendments are enacted.

Turning first to the proposed Clean Air act legislation, both the Senate and the House have addressed the WEPCO issue. The Senate language appears in section 415. While section 415 deals mainly with Clean Coal Technology projects, it also covers other pollution control projects. Specifically, Section 415(e) (3) (B) which reads as follows:

> Any permanent clean coal technology demonstration project that constitutes a retrofit project and, notwithstanding the provisions of paragraph (1), any other utility unit pollution control project, including but not limited to, alterations that allow the use of natural gas as a fuel, where such project constitutes a retrofit pollution control project and where such project complies with the State implementation plans for the State in which the project is located, and with other requirements necessary to attain and maintain the national ambient air quality standards shall not be deemed to be a major modification subject to the review and permitting requirements of part C or D of Title I: Provided, That the project will not result in a significant net increase in actual emissions of any pollutant regulated under this Act. For purposes of this subsection, the Administrator shall presume that a retrofit project will not result in an increase in the capacity utilization of the source. This presumption may be overcome if the administrator concludes, based on information submitted pursuant to regulations or interpretative rulings promulgated under this section, that there is a likelihood that hours of operation or rates of production will increase because of the retrofit project. For purposes of this subsection, 'retrofit project' is defined as the permanent installation or operation of an emissions control system or device designed primarily to improve the control or prevention of emissions of any air pollutant, other than a repowering as defined in section (402) (1) of this title.

In the House of Representatives the language specifically addressing Clean Coal Technology projects appears in section 515. In addition, WEPCO is addressed in section 707 and in section 512(b) of H.R. 3030. Section 512(b) reads as follows:

> New Source Review of Compliance--No physical change in, or change in the method of operation of, a stationary source for purposes of reducing emissions from such source in order to comply with this title shall be treated as a modification for purposes of section 111 or Part C of Title I of this Act if such change does not increase the potential emissions of any air pollutant from such source above the potential emissions prior to the change.

Reviewing this language shows that both the House and the Senate have addressed only a limited portion of the WEPCO policy. They simply cover

pollution reducing projects and clean coal technology projects. Both indicated that EPA cannot extend the WEPCO policy to affect changes required to conform to the provisions of the proposed Clean Air Act Amendments.

However, in reviewing the two (2) legislative proposals, it is apparent that the Senate version does not convey as adequate and clear a message to EPA as the House version. For example, the Senate language is incorporated into Section 415 which deals with Clean Coal Technology programs. The WEPCO language was incorporated into the bill in what appears to be an afterthought. As such, the effectiveness of the language might be weakened. By contrast, the House of Representatives has specifically delineated the WEPCO issue for non-clean coal technology power plants as a separate and distinct section. Additionally, the Senate language addresses only the PSD aspects of the WEPCO policy while the House addresses both PSD and NSPS. As a result, the House provision is preferable to the Senate provision.

At this point in the WEPCO saga, a clear expression of Congressional guidance is significant and necessary. Let me relay an example from my Company's experience to illustrate the need for Congressional action. Northern Indiana is the host site for a Round II, Department of Energy Clean Coal Technology project. The project involves the construction and operation of a full sized advanced flue gas desulfurization (AFGD) system. The AFGD will be operated as a demonstration project for three (3) years with the Department of Energy co-funding construction and the operation during the demonstration period. At the conclusion of the demonstration, if the system meets certain performance standards, the AFGD will begin commercial operation for a seventeen (17) year period.

Following issuance of the EPA's decision in the Port Washington case, Northern Indiana requested clarification of the NSPS and PSD issues for the AFGD project.

The EPA issued a letter dated July 14, 1989 which indicated that Northern Indiana could potentially be subject to NSPS or PSD review if the project operated for over five (5) years. Northern Indiana requested further clarification in light of the fact that a proposed change to the power plant was the installation of device intended to remove over 90% of the potential sulphur dioxide emissions seven and one-half years prior to any of the requirements of pending Clean Air Act legislation. EPA's initial verbal analysis indicated that PSD would in fact apply. EPA indicated that a best available control technology analysis would be required, but that by netting out emissions, this review could be avoided. Netting out would have involved placing restrictions on the operations of the power plants and artifically forcing them to operate at reduced levels throughout the year. Northern Indiana reviewed the situation and determined that netting out was not a viable option. Artificial restrictions would preclude the company's ability to meet customer's needs in the future and could require additional capacity to be constructed earlier than currently planned.

Rather, we chose to discuss the issue further with agency representatives. These discussions led to letters dated January 5, 1990, January 30, 1990 and March 8, 1990. (Copies of the January 30 and March 8 letters are attached.) In these letters, EPA established that NSPS and PSD would not apply to the project. However, EPA announced that they would be issuing an interpretative ruling providing further clarification of the applicability of NSPS and PSD in situations where utilities were

reducing emissions. Although promised since the beginning of 1990, no such ruling has been issued. Further, this ruling is being developed and issued without input from the electric utility industry or any other impacted group. Thus, EPA is launching a key and dramatic departure from previous policy without benefit of input from at least one industry directly impacted by the policy. As such, Congressional action is necessary to clearly mandate the direction which EPA should follow. The Senate language needs to be strengthened and raised to at least the level of the House of Representatives' bill.

However, as I previously noted, the language in the pending Clean Air Act legislation does not address all WEPCO issues. The WEPCO policy will limit the ability of utilities to operate and maintain power plants in a reliable fashion. In the future, EPA could severely limit the repair of existing power plants and the changes which could be made to provide low cost electric service to our customers. EPA has totally ignored the cost impacts of its WEPCO decision. Further, no assessment of the impact on reliability of electric supply has been conducted. Many forecasters are predicting that electric energy shortages will occur in the 90's in many areas in America. This situation will be heightened by EPA's WEPCO policy. Through 1995, Applied Economic Research Company has determined that the WEPCO policy could affect the reliability of the supply of electricity in regions where as many as 138 million people live.[4] The Agency's interpretations cause declining reliability by restricting cost effective maintenance programs, cause operations at progressively lower capacity levels and force early retirement of plants. These effects could reduce installed capacity by 34 gigawatts by 1995, which is almost half of the new capacity that customers will need to meet anticipated growth in demand during the next eight years.[5] EPA's WEPCO policy also

has adverse environmental implications. Given the current uncertainty, plant owners and operators will likely decline to undertake projects that would improve efficiency, maintain reliability, reduce costs, or improve emissions control. This situation is hostile to EPA's and the Department of Energy's efforts to reduce emissions of pollutants that may contribute to "global warming." Henson Moore, Deputy Secretary of Energy, has stated that "for every five percent improvement in the efficiency of coal combustion, we reduce carbon dioxide emissions from that plant by 15 percent."[6]

The United States Congress, in deliberating the Clean Air Act legislation this year, has worked to strike a balance between the cost and the benefit of increased environmental control on air emissions. This legislation addresses SO_2, NO_x and likely particulate emissions from utility power plants. After crafting such legislation, EPA could significantly alter that balance through application of the WEPCO policy. Thus, while Congress is preparing to chart a course for the country's environment and energy future, EPA by application of existing laws, can dramatically sway that direction, substantially increase costs and reduce electric reliability.

EPA has shown an intent to do exactly that. As previously discussed, after the Seventh Circuit Court decision, EPA has attempted to limit the application of the court's decision to projects involving the repair of a power plant component with a like-kind or similar component rather than undertake a rulemaking. This action clearly shows EPA's desire to press its WEPCO logic to the maximum extremes possible.

In summary, the United States Senate should adopt language similar to section 512 (b) of the House bill addressing the WEPCO issues as it relates to the measures taken by companies in response to the Clean Air Act.

Further, action is needed to review the energy cost and reliability impacts of the WEPCO issue so that EPA receives congressional guidance on those matters. Legislative direction limiting the application of the WEPCO policy should be given where utilities:

1. increase the efficiency or reliability of existing units through physical or operational alterations;
2. maintain and modernize existing units or
3. make needed in-kind component replacements.

Thank you for this opportunity to share these concerns with you. Northern Indiana, and I am sure the electric utility industry, stand ready to work with you to resolve concerns raised by the WEPCO policy.

[1] Memorandum from Edward E. Reich to Michael W. Johnson (July 28, 1983).

[2] Letter from Christopher J. Daggett to Pedro A. Santiago Rios (May 4, 1988).

[3] Letter from Edward E. Reich, EPA Director, Division of Stationary Source Enforcement, to Amasjit Gill, General Electric (June 24, 1981).

[4] Applied Economic Research Company, Potential Effects of Restricted Power Plant Maintenance On The Adequacy Of U. S. Electricity Supply 1989-1995, pg. iii

[5] Ibid., pgs. 5 and 6.

[6] Energy Daily (February 26, 1990).

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
230 SOUTH DEARBORN ST.
CHICAGO, ILLINOIS 60604

REPLY TO THE ATTENTION OF:

March 8, 1990

Mr. Timothy J. Method
Assistant Commissioner
Office of Air Management
Indiana Department of Environmental Management
105 South Meridian Street
Post Office Box 6015
Indianapolis, Indiana 46206-6015

Dear Mr. Method:

Please be advised that my January 30, 1990, letter to your regarding the Clean Coal Technology (CCT) project at Northern Indiana Public Service Company's (NIPSCO) Bailly Generating Station, should be modified. While the Environmental Protection Agency (EPA) continues to agree with the State that Clean Air Act (CAA) provisions for new source performance standards (NSPS) and new source review (NSR) do not apply if the conditions outlined in my January 30, 1990, letter are met, some revisions are necessary.

On page 8, the section on "Conditions for Permanent Controls or Devices to Be Considered Not Less Environmentally Beneficial" should be changed as follows:

In first paragraph, second sentence (change underlined) -

"At this time, EPA anticipates that its ruling will include a presumption that such pollution controls will not result in an environmental harm, with respect to permanent controls, if the source demonstrates that:"

In the second condition (change underlined) -

"2. There will be no environmental harm resulting from the proposed activities. This includes conditions that the proposed change would not by itself:

(a) ...(no change)...;

(b) increase the annual emissions of any pollutant regulated under the CAA;" (delete the phrase "as a result of increased capacity utilization rate)

Insert new paragraph after condition 2d -

"Changes which are expected to increase emissions to the atmosphere, such as changes which increase a source's hourly operating capacity (e.g., eliminating a bottleneck), hourly emissions rate (e.g., one pollutant decreases but another increases), or utilization rate (e.g., an anticipated increase in hours of operation resulting from the installation of control) would not be affected by this interpretation and would continue to be potentially subject to NSR and NSPS. The EPA will presume, however, that the addition of a control device will not, by itself, result in an increase in capacity utilization. However, this presumption will be overcome if there is a clear likelihood that operating hours or production rates will increase because of the installation of the device.

On page 10, a corresponding change should also be made to amend the first full paragraph as follows (change underlined):

"The EPA also anticipates that its interpretative ruling will... In assessing whether any net increase in actual emissions of any pollutant, over representative actual emission rates, is likely to occur as a result of the addition of controls, the reviewing agency should consider the economic incentives to increase production rates or hours of operations associated with the installation and use of the control device. Where increased emissions due to increased utilization of the facility are clearly a likely result from addition of the device, the change should not be considered environmentally beneficial." (Delete last sentence of paragraph starting with "The authority...).

If you have any further questions, please contact Mr. Ron Van Mersbergen at (312) 886-6056.

Sincerely yours,

David Kee, Director
Air and Radiation Division

cc: William R. Elliott, NIPSCO
Thomas F. Anderson, Save the Dunes Council

TOTAL P.03

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
230 SOUTH DEARBORN ST.
CHICAGO, ILLINOIS 60604

JAN 30 1990

REPLY TO THE ATTENTION OF

RECEIVED

FEB 01 1990

Office of Air Management

Mr. Timothy J. Method
Assistant Commissioner
Office of Air Management
Indiana Department of Environmental Management
105 South Meridian Street
P.O. Box 6015
Indianapolis, Indiana 46206-6015

Dear Mr. Method:

The purpose of this letter is to comment on the permit proposed by the Indiana Department of Environmental Management (IDEM) for Northern Indiana Public Service Company's (NIPSCO) Bailly generating station. The permit provides for the construction of an air pollution control device and directly related improvements under the Clean Coal Technology (CCT) program. The Environmental Protection Agency (EPA) agrees with the determination by IDEM that the State and EPA rules for prevention of significant deterioration (PSD) and new source performance standards (NSPS) are not intended to apply to the CCT project at Bailly. In other words, the project should not be considered a "major modification" under new source review (NSR) or a "modification" as set forth under NSPS provided certain requirements are met. In a separate but related issue, EPA also agrees with the determination by IDEM that the addition of a diesel generator as a backup power supply to the scrubber to be installed at Bailly is not a major modification if the limits on operating the generator agreed to by NIPSCO are federally enforceable.

Introduction

For NSPS purposes, a modification is defined as any physical change in, or change in the method of operation of, a stationary source which increases (in terms of hourly emissions capacity) the amount of any air pollutant regulated under the Clean Air Act (Act) which is emitted by such source, or which results in the emission of any air pollutant not previously emitted. For NSR purposes, a major modification is a modification which results in a significant net emissions increase (in terms of actual annual emissions).

The EPA has become aware that these definitions can be interpreted in such a manner as to subject to NSR or NSPS, or both, certain environmentally desirable activities at existing stationary sources which neither Congress nor EPA intended to be covered by the Act's new source requirements. Moreover, NSR or NSPS coverage would, in some instances, have the effect of discouraging such activities. The EPA believes that such activities, including CCT demonstration projects, are not physical changes or changes in the method of operation, so long as they meet certain criteria discussed herein and EPA issues an applicability exclusion. Hence, such activities are not "modifications" for NSPS purposes, or "major modifications" for NSR purposes.

Over the past several months, EPA has held numerous internal meetings to discuss the Clean Air Act regulatory issues raised by the CCT program. As a result of these discussions, the EPA has decided to issue an interpretative ruling as soon as possible to provide guidance on the definition of a physical or operational change as it applies to new source requirements. In a letter dated January 5, 1990, EPA advised NIPSCO of this intention.

Essentially, this ruling would clarify that if a source solely adds or enhances systems or devices whose primary functions are the reduction of air pollution, and that are determined to be not less environmentally beneficial (as determined by the Administrator) than any emission control system or device it replaces, if any, such activities would not constitute a physical or operational change triggering new source requirements. Consequently, NSPS and PSD and nonattainment new source review would not apply to these types of activities. This interpretative ruling would include permanent, as well as temporary projects under the CCT program. However, it would not extend to projects that primarily are intended to extend the life of a plant or increase capacity. In addition, any changes, permanent or temporary, which are expected to significantly increase emissions to the atmosphere, such as changes which increase a source's hourly operating capacity (e.g., eliminating a bottleneck), hourly emissions rate (e.g., one pollutant decreases but another increases), or utilization rate (e.g., an anticipated increase in hours per year of operation resulting from the installation of controls) would still be subject to NSR and NSPS.

Based on our review of the draft permit, we believe that the Bailly project is consistent with the provisions EPA is developing for its interpretative ruling. On this basis, we have reached the conclusion that this project in particular is not subject to NSPS or major NSR requirements, so long as it continues to meet the criteria discussed herein.

The balance of our comments outlines the grounds for EPA's conclusion and contains a discussion of the anticipated terms of EPA's upcoming interpretative rule. The EPA is still deliberating the specific terms and provisions of its interpretative ruling. While today's comments reflect EPA's current expectations of what will be contained in that document, the actual terms of the ruling may differ from those discussed herein.

Background

A. The NSR and NSPS Provisions of the Clean Air Act

The NSR and NSPS provisions of the Act apply to wholly new facilities, and to modifications at existing facilities, when certain conditions are met. The rules governing the applicability of NSR and NSPS to modifications at existing facilities are described in detail in the EPA regulations (see 40 CFR 51.165 and Appendix S, 52.21, 60.14 and 60.15). In general, the modifications that would trigger these new source requirements are those involving physical or operational changes which increase emissions over baseline levels. (In addition, for NSPS purposes under EPA regulations, a reconstruction occurs and a source is considered "new" if the physical or operational change costs more than 50 percent of the replacement cost of the

affected facility, regardless of whether an emissions increase occurs). The term "physical or operational change" is construed broadly and may include the installation, use, or dismantling of pollution control equipment.

1. Background of the NSPS and NSR Modification Provisions.

The 1970 Amendments to the Act required EPA to promulgate technology-based new source performance standards applicable to the construction or modification of stationary sources that cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. 42 U.S.C. 7411(b)(1)(A). Congress decreed that, in addition to wholly new sources, NSPS would apply to the modification of an existing source, defined broadly as: any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Clean Air Act section 111(a)(4), 42 U.S.C. 7411(a)(4).

The NSPS provisions were "designed to prevent new [air] pollution problems" by regulating both newly constructed sources of pollution and existing sources that increase their emissions. National Asphalt Pavement Assoc. v. Train, 539 F.2d 775, 783 (D.C. Cir. 1976) [see also H.R. Rep. No. 1146, 91st Cong., 2d Sess. 3, reprinted in 1970 U.S. Code Cong. & Admin. News 5356, 5358]. The effect of including modified sources as well as newly-constructed sources under the provisions of section 111 was to establish a current level of emissions above which an existing source may not pollute without becoming subject to the NSPS. In August 1977, Congress adopted further extensive changes to the Act (Pub. L. 95-95). These included review-and-permitting programs for new and modified sources combining the technology-based approach of NSPS with specific measures to insure that ambient air quality goals under the Act are met. Congress intended NSR to apply "where industrial changes might increase pollution in an area." Alabama Power Co. v. Costle, 636 F.2d 323, 400 (D.C. Cir. 1979). Part D applies to areas which have not met national ambient air quality standards (NAAQS) under section 109. To receive a permit in such areas, major new and modified sources must (among other things) obtain emissions offsets that assure reasonable progress toward attainment of the NAAQS and must comply with the "lowest achievable emission rate," which can be no less stringent than an applicable NSPS (see sections 171-173). The 1977 amendments also added a new Part C to the Act including, in sections 160 - 169, an NSR program for the prevention of significant deterioration of air quality (the "PSD" program) in areas which have attained the NAAQS. To receive a PSD permit, a prospective major new or modified source must (among other things) show that it will not exceed the available air quality "increment" (designed to prevent pollutant concentrations from deteriorating beyond certain levels), and will use the "best available control technology", which must be at least as stringent as any applicable NSPS. Both the Part D NSR program applicable to nonattainment areas and the Part C NSR program applicable to attainment areas adopted the NSPS definition of "modification," but not all the exclusions to that definition [see sections 171(4) and 169(2)(C)].

It is evident from the structure of the NSR and NSPS programs that Congress sought to focus air pollution control efforts at an efficient and logical point: the making of substantial capital investments in, or other long-term decisions regarding, pollution-generating facilities. In adopting NSR measures in particular, Congress sought to reconcile the legislative goal of environmental protection with a concurrent desire for continued economic growth [see sections 160(1)-(4)]. Consequently, a key theme of the NSR program is the careful evaluation of, and public participation in, "any decision to permit increased air pollution" [see section 160(5)]. As discussed below, the current regulations implementing NSPS and NSR were designed to apply these programs in a manner consistent with their respective statutory purposes. Today's comments represent our interpretation of these existing regulations under the facts presented by the Bailly project. The EPA expects that its upcoming interpretative ruling will further focus EPA's position on the basic legislative intent of these important programs.

2. The Two-Step Test for Modifications.

The modification provisions of the NSPS and NSR programs grow from a single statutory trunk, the very broad definition of "modification" in section 111(a)(4). Under both respective programs, EPA developed a two-step test for determining whether activities at an existing facility constitute a modification subject to new source requirements. In the first step, which is largely the same for NSPS and NSR, EPA determines whether a physical or operational change has occurred. If so, EPA proceeds in the second step to determine whether the physical or operational change will result in an emissions increase over baseline levels. In this second step, the applicable rules branch apart, reflecting the fundamental distinctions between the technology-based purposes of NSPS and the technology and air quality concerns of NSR. Briefly, the NSPS program is concerned with <u>hourly</u> emissions rates, expressed in kilograms or pounds per hour. [An hourly emissions rate is the product of the instantaneous emissions rate, i.e., the amount of pollution emitted by a source, after control, per unit of fuel combusted or material processed, (such as pounds of sulfur dioxide emitted per ton of coal burned) times the production rate (such as tons of coal burned per hour)]. Emissions increases for NSPS purposes are determined by changes in the hourly emissions rates at maximum capacity. The NSR is concerned with total annual emissions to the atmosphere, expressed in tons per year. (Annual emissions are the product of the hourly emissions rate, which is the sole concern of NSPS, times the utilization rate, expressed as hours of operation per year). Emissions increases under NSR are determined by changes in <u>annual emissions</u> to the atmosphere.

3. Physical or Operational Change.

The very broad definition of physical or operational change in section 111(a)(4) could, standing alone, encompass the most mundane activities at an industrial facility -- even the repair or replacement of a single leaky pipe or a change in the way that pipe is utilized. The definition certainly is broad enough to encompass the addition or enhancement of pollution control equipment. However, EPA has always recognized that Congress obviously did not intend to require every activity to be potentially subject to new source requirements, and that it would be administratively impracticable to do so. Accordingly, EPA has substantially narrowed this term in its NSPS and NSR

regulatory definitions through the adoption of common-sense exclusions. For example, both sets of regulations contain similar exclusions for routine maintenance, repair, and replacement; for certain increases in the hours of operation or in the production rate; and for certain types of fuel switches [see 40 CFR 60.14(e); see also, e.g., 40 CFR 52.21 (b)(2)(iii)]. In addition, with respect to pollution control equipment, the NSPS regulations contain an exclusion for:

> The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial [40 CFR 60.14(e)(5)].

The EPA has held that this exclusion does not apply to a source which, upon original construction, employed wet scrubbers, but later (upon relaxation of a State plan under section 111(d)) desired to remove the control equipment, which would have resulted in much higher levels of pollution than the plant had ever emitted [National Southwire Aluminum Co. v. EPA, 838 F.2d 835 (6th Cir.), cert. denied, 109 S.Ct. 390(1988), herein after National Southwire]. In the past, EPA has taken various views as to whether the exclusion in section 60.14(e)(5) should apply for NSR purposes. As noted earlier, the NSR statutory definitions of modification simply adopt the NSPS definition in section 111(a)(4). In addition, the legislative history reflects that, as a general matter, Congress intended to conform the meaning of "modification" for PSD purposes to usage under NSPS [see 123 Cong. Rec. H11957 (Nov. 1, 1977)]. For this reason, EPA initially ruled that the NSPS exclusion for addition of control devices applied automatically to PSD (Memorandum from Edward E. Reich, OAQPS, and William F. Pedersen, OGC, to EPA Region VI, April 21, 1983). The EPA reversed course in a 1986 applicability determination issued for both PSD and nonattainment NSR purposes, noting that the NSPS exclusion was highly qualitative, and failed to give due account to either the air quality management component or the largely quantitative orientation of the NSR applicability regulations. (Memorandum from Gerald A. Emison, Director, OAQPS, to Regional Air Division Directors, July 7, 1986).

Comments on NSPS Applicability

An NSPS modification is any "physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies" (40 CFR 60.2). Under NSPS, emissions increases, for applicability purposes, are calculated by comparing the hourly emission rate immediately before and after the physical or operational change. All operating parameters which may affect emissions must be the same to the maximum feasible degree for the before and after testing, and tests must be conducted under representative conditions. Absent the exclusions from modifications specified at 40 CFR 60.14(e), any increase in emissions to the atmosphere over the previous emissions rate will subject the modification to NSPS [see section 60.14(a) and (b)]. In addition, modifications which would cost 50 percent or more of the cost of a comparable new facility are classified as reconstruction (see 40 CFR 60.15) and are subject to NSPS as a new source even if there is no emissions increase.

Thus, unless the reconstruction provisions come into play, it is clear that under the existing regulations NSPS would not apply to the installation or improvement of emission control equipment which reduces hourly emissions rates. If the reconstruction provisions do apply, then such changes would trigger NSPS.

Based on NIPSCO's permit application and representations made by NIPSCO's September 14, 1989 and December 4, 1989 information submittals to EPA, NSPS would not apply to the Bailly Station if the new scrubber is not removed (i.e., if it is a permanent demonstration) because hourly emission rates will not increase as a result of the addition of these CCT controls. As a permanent CCT demonstration project, it would satisfy the requirements of the exemption contained in 40 CFR 60.14(e)(5) for the addition or use of any control system or device whose primary function is the reduction of air pollution. (The definition of "modification" for NSPS is found at 40 CFR 60.14). In addition, the Bailly project would not qualify as a reconstruction under 40 CFR 60.15.

However, the NSPS provisions could also apply to major facilities with temporary CCT demonstration projects at the end of the demonstration when the control equipment is removed and emissions rise back to the level that existed before the demonstration. Thus, while the placement of CCT controls at Bailly will reduce the hourly sulfur dioxide (SO_2) emissions rate, if NIPSCO later dismantles the CCT controls, this would result in an increase in hourly SO_2 emissions up to pre-demonstration levels and the source could be considered subject to NSPS.

Today's comments reflect EPA's position that the Bailly plant would not be subject to NSPS at the conclusion of the project, if NIPSCO decides to make it only temporary, as the result of an increase in emissions rates back up to the levels which existed before the changes were made to accommodate the temporary demonstration project. The EPA expects that its forthcoming interpretative rule will take this position with respect to all temporary CCT and similar demonstration projects which reduce emission rates. Unlike the situation presented in National Southwire, it is clear that the addition of pollution control in a temporary CCT demonstration was never intended to result in permanent emissions reductions. In addition, removal of temporary controls will not result in a level of emissions higher than that experienced in the past. (Reconstruction provisions, however, could subject both temporary and permanent CCT demonstration projects, and certain other emission control system installations or improvements, to NSPS. Still, as indicated by the Bailly project, the reconstruction provisions of the Act should rarely, if ever, apply to the type of activity which would be considered for exclusion from the definition of a physical change or a change in the method of operation. Thus, the triggering of the reconstruction provisions is an indication that the proposed activities are more extensive than just the addition, or replacement, of an emission control system or device, and so are not appropriate for exclusion.)

Comments on NSR Applicability

Modified sources are subject to NSR if the modification is "major." Major modifications must consist of a physical change or change in the method of operation of a major stationary source [40 CFR 52.21(b)(1)] which results in a net emissions increase of any pollutant subject to regulation under the Act that is significant. Significance levels are expressed in tons per year and differ for each pollutant [40 CFR 52.21(b)(23)]. Net emissions increases are determined [40 CFR 52.21(b)(3)] by summing all contemporaneous creditable actual emissions increases and decreases. The definition of "actual emissions" is such that generally the comparison is between actual emissions before the physical or operational change in question and the potential to emit of the facility afterwards [40 CFR 52.21(b)(21)]. If the source has not been operating near full capacity, even the addition of a control device could be considered a significant net emissions increase when comparing historic actual emissions with a new potential to emit, even though there may be a substantial reduction from historic actual emissions.

Specifically, actual emissions before the change at a facility are generally determined by averaging the emissions for the 2 years prior to submittal of the permit application (or some other period if the last 2 years are not representative of normal unit operation) [see, e.g., section 52.21(b)(2)(ii)]. Since the emissions rate after a physical or operational change cannot be predicted in advance, EPA regulations assume that a source's actual emissions will equal its maximum "potential to emit", which is based on constant full load operation for an entire year (unless restricted by federally enforceable limitations) [see, e.g., sections 52.21(b)(21)(iv); 52.21(b)(4)]. Thus, a physical or operational change will trigger NSR if the annual potential to emit of the source is significantly greater after the change than its representative actual annual emissions before the change, unless the company agrees to federally enforceable operational restrictions which limit its potential to emit to levels not significantly greater than its actual emissions before the change. This actual-to-potential methodology applies to physical or operational changes at new or "modified" (i.e., altered or changed) emissions units [see 45 FR 52676, 52677, 52718 (1980)].

As explained below, EPA believes that this methodology generally serves the purposes of NSR because it subjects to review projects that might lead to an increase in actual pollution. However, the NSR provisions in the existing regulations could be interpreted to apply to major facilities simply installing or improving control equipment, including CCT demonstration projects, under circumstances where a permanent increase in pollution is highly unlikely.

Under EPA's prospective interpretative ruling, existing sources which would otherwise become subject to NSR only because they decide to install or improve emission controls, or participate in the CCT program or similar demonstration projects approved by EPA, would instead be excluded from NSR coverage, so long as certain criteria intended to ensure that permanent increases in actual emissions do not occur are met.

With respect to the Bailly project in particular, it appears that the plant has been operated at a rather high level of approximately 60 percent of capacity, reflecting baseload utilization of the plant. There is no

indication that NIPSCO intends to increase this level of usage at any time following installation of the OCT controls. In addition, it appears that the Bailly project will meet the criteria EPA expects to set forth in its interpretative ruling for both temporary and permanent projects.

The EPA now believes it is appropriate to devise and apply such criteria both for the Bailly project and for the upcoming interpretative ruling. The EPA has recommended the position taken in its 1986 memorandum, discussed earlier, regarding use of the NSPS exclusion in 40 CFR 60.14(e)(5). While EPA continues to believe that this exclusion does not apply automatically for NSR purposes, the criteria discussed herein provide due consideration of air quality management concerns and the need for quantitative analyses.

Conditions for Permanent Controls or Devices to be Considered Not Less Environmentally Beneficial

As noted above, EPA is preparing an interpretative ruling which will clarify that if a source solely adds or enhances systems or devices whose primary functions are the reduction of air pollution, and which are determined to be not less environmentally beneficial, such activities would not constitute a physical or operational change triggering new source requirements. At this time, EPA anticipates that its ruling will provide that such pollution controls will be considered not less environmentally beneficial, with respect to permanent controls, if they meet at least the following criteria:

(1) The source will continue to meet all current requirements and standards applicable to existing sources under the Act. This includes meeting applicable NAAQS, PSD increments, permit conditions, and State implementation plan (SIP) limitations.

(2) There is no environmental harm resulting from the proposed activities. This includes conditions that the proposed activities would not cause the source to;

(a) increase the maximum hourly actual emissions rate of any pollutant regulated under the Act;

(b) increase the annual emissions of any pollutant regulated under the Act as a result of an increase in capacity utilization rate;

(c) adversely impact an air quality related value (e.g., visibility) in any Class I area; or

(d) allow an increase in emissions of toxic pollutants not regulated by the Act which would cause an adverse health or welfare impact.

Based on the information provided by NIPSCO, it appears at this time that the Bailly project, if it is made permanent, will meet the above criteria. Accordingly, as to the Bailly project in particular, EPA believes that major NSR requirements clearly will not apply if the project is made permanent, so long as these criteria are in fact met.

Temporary CCT Changes

In its upcoming interpretative ruling, EPA expects to follow criteria for "temporary" CCT projects which are somewhat different from those for permanent projects. The EPA likely will consider a project to be temporary if it lasts less than 5 years from the date the project commences construction. However, the ruling probably will provide that the Administrator would consider an additional period of time, up to 5 additional years, in certain cases. At the end of a temporary project, the facility would be returned to pre-demonstration conditions and hourly emission rates (or lower). It is not clear if the proposed Bailly station permit is for a permanent or temporary CCT project. It is our understanding that NIPSCO considers the first 3 years of the CCT demonstration project to be "temporary" and will view the changes as "permanent" for the following 17 years if they are continued after the 3 year period.

The EPA expects that its interpretative ruling will provide that for temporary demonstration projects, the conditions relating to actual emissions increases and hours of operation criteria under 2a, b and d above would not apply to minor, temporary variations from nominal operating conditions. Temporary increases may occur due to testing procedures or some failure in unique but unproven equipment, but should not willfully contribute to adverse health or welfare impacts. The EPA believes that the benefits inherent in CCT and other similar technology demonstration projects counterbalance the limited, temporary impacts that may occur during these temporary projects. Under the ruling, temporary demonstration project applications likely would have to meet all of the other criteria applicable to the permanent projects discussed above. This interpretation would provide the flexibility to encourage temporary demonstration projects which are considered to be environmentally beneficial overall, despite unpredictable, temporary increases in emissions of some pollutants or in the hours of operation that may occur during the course of a demonstration.

The EPA expects the ruling to state that temporary changes would become permanent at any time during or at the end of a demonstration period if the owner/operator seeks a revised applicability determination addressing all criteria applicable to permanent air pollution control system improvements. In submitting these comments, EPA is applying the above criteria in its review of the Bailly project. If NIPSCO ultimately decides that the Bailly CCT project is to become a permanent CCT demonstration, the project should meet all the criteria discussed earlier for permanent projects at the time the project is to be converted to permanent status (i.e., after 3 years).

Procedures for Environmentally Beneficial Exclusions from Applicability

The EPA expects that under its forthcoming interpretative rule, an owner or operator proposing to make an environmentally beneficial change in an air pollution control system will be called upon to request an applicability determination from the appropriate NSR/NSPS permit authority. The request should include a general description of the facility and the proposed activity, information on the current and projected use of the facility, and

sufficient information to justify a nonapplicability determination. For any air pollution control system improvement, the request should include a rationale for why the emission control system or device should be considered equal to or more efficient than existing control technology at the source.

The EPA also anticipates that its interpretative ruling will state that in providing information to the reviewing authority, an owner or operator should submit sufficient modeling to demonstrate that any new or increased emissions of unregulated toxic pollutants resulting from the change in control equipment will not cause or contribute to adverse health or welfare impacts. The owner or operator should also demonstrate that the source will not operate at greater hourly emissions rates, or for more hours, than it has been during the most recent 2 years (or some other period, if the last 2 years are not representative of normal operation). In assessing whether actual emission increases of any pollutant are likely to occur, the reviewing agency should consider the economic incentives to increase production rates or hours of operation associated with the change. Any change which could reasonably result in increased emissions due to possible increased utilization of the facility as a result of the changes should not be considered environmentally beneficial. The authority reviewing the proposed change should explicitly determine, based on consideration of these and other relevant criteria, that the net effect will not be one of environmental harm.

Operating Limits on New Diesel Generator

The EPA considers the addition of a backup diesel generator at Bailly not to be an integral part of the CCT demonstration, in that the generator could serve multiple functions once installed. In general, EPA views changes to be subject to NSR and NSPS if such changes are not strictly related to the addition of the improved air pollution control system and the changes have any possible additional application. However, EPA agrees with IDEM that the addition of a new diesel generator does not constitute a "major modification" if the State's limits on the generator's hours of operation, preventing concomitant increases in emissions from exceeding significance levels, are federally enforceable.

In closing, EPA agrees with the State that NSPS and NSR do not apply if the conditions outlined in this letter are met. If you have any further questions, please contact Mr. Ron Van Mersbergen at, (312) 886-6056 or Mr. Dom Abella at, (312) 886-6543.

Sincerely yours,

Jerry F. Kelly, for

David Kee, Director
Air and Radiation Division

Senator FORD. Thank you very much. I will have several questions to ask, and then, because of the time, and I am under time constraint, that there will be some questions sent to each of you in writing, and I hope that you will respond in a timely manner, and we can get those in the record.

Mr. Schmalensee, could you summarize what your proposal means for—and I will give you four or five different ones here, if you want to note them—natural gas cofiring, oil to gas conversions, clean coal retrofit, clean coal repowering and industrial facility modifications?

Is that too much for a non-lawyer to do?

Mr. SCHMALENSEE. Well, Mr. Chairman, could I do these one at a time?

Senator FORD. You can do them one at a time. If you want to give them to me in writing, I will be glad to accept that, if you can do that in a short period.

Mr. SCHMALENSEE. I think I can probably give you a better answer in writing than stumbling through these here. But let me say, in a number of these—first of all, you mentioned industrial facilities at the end, I believe. We intend this, our proposal, to apply just to electric utility units at this stage. We do not have a position on industrial units.

And as to the others, I would be happy, and I think it would be useful to respond in more detail in writing, but just let me point out that for any of them, we would go through a number of steps. We would look at the impact on local air quality, we would look at whether the project was a pollution control project or a non-pollution control project, and we would apply the test indicated in the testimony.

But I think this is sufficiently complicated, that it ought to get a full written response, if I may.

Senator FORD. That will be fine.

Mr. Blake, since you are a former general counsel at EPA, you interest me.

[Laughter.]

Senator FORD. So I want to ask you a question, now that you are out. Why, in your view, did the Agency in 1988, change its longstanding interpretation of the new source review regulations and come up with the ungodly WEPCO policy?

Mr. BLAKE. I am not fully aware of all the reasons behind it. I think, in fairness to the Agency, they had some concerns that, really as Mr. Schmalensee addressed right at the outset, that a major life extension project of facilities could be undertaken and avoid the new source performance standards and new source review provisions of the Act. I am probably not the right person to defend that decision, but I would say that they had some legitimate concerns underlying it.

I think the difficulty with all of these issues is, the first cut may look logical enough, but as the thought pattern is extended out into each new application and you start just following the pure logic of the law rather than looking at the practicality of the situation, you find yourself in the spot where we are now, where you have some very positive projects, and some innovative pollution control ap-

proaches that are being thwarted by the policy. I do not believe that was the Agency's intent in the first instance.

Senator FORD. Doctor, you have a EPA representative with you. Would he care to acknowledge or state why the Agency changed their long-standing interpretation? Why don't you come down to the end of this chair down here. You will not have to get on your knees.

[Laughter.]

Mr. FOOTE. Not an unfamiliar position lately, I'm afraid.

[Laughter.]

Senator FORD. Ah, well, there are no rings around.

Mr. FOOTE. To elaborate on the statement Frank Blake just made, I think that, giving even a bit more fairness to the Agency, that the Agency's administrative WEPCO decision did not represent any change in policy on the part of EPA. It resulted—rather, it reflected a case-specific application of regulations that have been in effect since 1980. And I am referring specifically to the two pertinent aspects of that decision, which is, what is a physical change, routine versus non-routine, and the test for emissions increase, the so-called actual two potential tests.

I think what is—the particular reason why WEPCO has gained such notoriety, other than the potential application down the road that Mr. Blake just indicated, is that this question of utility life extension is a relatively new development, and this was the first case involving that phenomenon that was brought to EPA's attention.

Senator FORD. Well, I recall—I believe it was Detroit Edison, where EPA said that an oil-to-gas conversion triggered new source review. Is that part of the WEPCO fix that we are getting into here?

Mr. FOOTE. It is an application of the same set of regulations to a different set of facts.

Senator FORD. Would you repeat that legalese to me again?

Mr. FOOTE. Well, if the question is——

Senator FORD. You said it is the same set of standards to a different set of facts.

Mr. FOOTE. That is right.

Senator FORD. How do you ever have the same facts all the time? They have to be pliable somehow, don't they, so they might fit the new facts. There are going to be changes all along, new technologies coming on board. Can you tell the committee, for the record, that WEPCO will be able to accommodate anything down the road?

Mr. FOOTE. There is always going to be some degree of uncertainty in applying a relatively static law and set of regulations to particular cases as they come along. These applicability questions have to be answered as they arise. They cannot all be answered in advance.

Senator FORD. I understand that.

Mr. FOOTE. I think that the suggestion in Dr. Schmalensee's testimony to have EPA develop guidelines as to what is routine and not routine, would be an example of a step that would reduce the degree of uncertainty in deciding which projects would potentially be subject and which would not, by elaborating on what is routine and what is not routine.

Senator FORD. Let me slip down there to Mr. Maassel.

Last Sunday Cable News Network, referred to as CNN, broadcasted a very interesting segment that I happened on and some others did, a report of possible brown-outs and black-outs on the East Coast, if we have a very hot summer. And during last December's cold wave, everybody was up to their potential, you know, if it was another degree we would have been in trouble in some of my information. There were rolling black-outs in December in parts of Florida, if you recall.

What effect does EPA's WEPCO policy have on the electric utility industry's ability to respond to these challenging circumstances, and they are challenging?

Mr. MAASSEL. It certainly makes responses to those kinds of things vastly more difficult. The uncertainty that we have means that we simply have no way of knowing if we begin to do something with a power plant, whether or not that is going to trigger a new source review in the applications of the regulations that exist at this time. That strongly encourages utility companies to be extremely cautious, and as a result, to perhaps defer maintenance, perhaps go to the Agency for clarification on the issue of whether or not the WEPCO policy will apply, and anytime you are in a case-by-case review, as EPA indicated, this policy will be used, you are immediately looking at an extended period of time.

Again, going back to my company's experience with the clean coal technology project, it took a total of about 9 months to simply find out that PSD and NSPS would not apply. In other projects and other situations, I am aware that it has taken much longer and no resolution has been reached, even yet today. So we are seeing a situation where the reliability of power plants will undoubtedly drop and the improvements that are necessary to keep power plants operating at peak efficiency and peak reliability simply cannot be made with any certainty.

Senator FORD. Well, Mr. Roberts, in view of his statement, let me ask you that in view of the difficulty of building new generating plants, does it make sense to pursue a policy that discourages life extension programs?

Mr. ROBERTS. Let me respond two ways. One is, as I made clear in my oral and written statement, we support certainty. We think that it would be useful to support certainty——

Senator FORD. You——

Mr. ROBERTS [continuing]. To the extent that the Agency can develop rules and that Congress can legislate clarifications to make this problem one where industry does not have a question about what the rules are, but in fact knows what the rules are, we would think that is preferable.

What we have said in our statement, and what Mr. Maassel has said and Mr. Schmalensee, is that we believe that the language contained in Mr. Sharp's proposal on the House side is sufficient to do the job.

Senator FORD. Mr. Maassel or Maassel, I mean, we will get it. You know who I am talking to.

Mr. MAASSEL. Absolutely.

Senator FORD. Was there a lot of interest in trying to get an answer for your 9 months delay, or was there pressure on EPA? Was everybody trying to scramble and get an answer so you could

move on with it, or is it just something that was routine that took you 8 to 9 months to get it back.

Mr. MAASSEL. We asked—the company itself, of course, approached EPA on several occasions. We met with congressmen and senators, and asked for their support in trying to reach an EPA decision. We approached the State of Indiana Department of Environmental Management and asked for their involvement and input, and we basically tried to talk to whomever we could to see if we could not expedite a project that we saw as being very beneficial, both in terms of the environment and in terms of the research and the development, to produce another project that could be used to fight acid rain.

Senator FORD. What was the attitude of the Department of Energy as it related to your problem?

Mr. MAASSEL. The Department of Energy was very interested in working with us to try and resolve the WEPCO implications. They have been interested in resolving the WEPCO implications on all clean coal technology projects to my experience, and they were, in fact, helpful in this project.

Senator FORD. We are moving, in this senator's opinion, and I have been at this since 1967, trying to work out some kind of clean coal technology, new uses, new sources, developing ways to use our own energy. And I think now, we have found one that, in all probability, will use both of our natural resources.

And I find that—I happened to be governor when we had an embargo in '73, I do not know whether you all remember that or not, and I was out driving 18-wheelers trying to distribute the energy to schools, hospitals, prisons, whatever. We were converting here and moving there. If we had not had a oil pipeline going through the State, I do not know what I would have done. I watched 200,000, I guess, employees in Ohio go without work for a long period of time. We developed ways to buy natural gas and make the pipeline transport it.

And I find now that we are about 54 percent imports of oil, if my figures are correct, and the embargo was about 28 percent. Then, when we are moving into the Clean Air provisions, no one faults that, and I think we are on the right track, but what I fault is trying to prevent new technologies, using our own ability to have our own energy source, rather than continue to be dependent.

I want to add one other little fact too, that we have about a $50 billion deficit as it relates to Japan. We have about a $50 billion deficit as it relates to oil and a balance of trade, and we have about $8 billion with the rest of the world. If we would solve the Japanese deficit, and the route we are going, we will have $150, $170 billion deficit, just in oil alone.

And we sit here today trying to jeopardize new technologies instead of trying to energize them, so that we might be able to stretch and improve the economy of this country. You are going to find in the next few weeks and months that the economy of this country is going to be severely called upon not to break. And I think the President has acknowledged that, since he has put new taxes on the table, and now wants to bring Congress in so he can blame them for increasing taxes.

So, I think we have to look very hard at all the sources we have and to encourage all the possibilities we have, without damaging the environment. I am not for breaking any rules, and hopefully, the support I gave to the energy—or the Clean Air Bill in the Senate, reflects my interest. But I do not want to get us in a position where we absolutely put our people out of business and we get into nothing but scrubbers. Because, the space, as we had testimony a few moments ago from the Department of Energy, space for scrubbers absolutely puts them in a position of not being able to continue to work, or looking for other resources. We find ourselves not pushing those other resources to make it work and to have clean emissions. I think we have to move hard.

We will, upon recessing this hearing, we will leave the books open for 30 days to accept answers to the written questions that I will submit to you, and anything that you think of that you have not said at this hearing, we will take that as an addendum. We are adjourned.

[Whereupon, at 4:41 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Questions

COUNCIL OF ECONOMIC ADVISERS
EXECUTIVE OFFICE OF THE PRESIDENT
WASHINGTON

MEMBER OF THE COUNCIL

July 23, 1990

Dear Chairman Ford:

Pursuant to my testimony of May 8, 1990, legislative language that addresses the WEPCO issue is enclosed. The Administration believes that language along these lines would both protect environmental quality and remove the uncertainty surrounding the application of the modification rule to electric utility plants as the electric utility industry makes the physical and operational changes necessary to meet new pollution reduction requirements under the Clean Air Act Amendments now under conference consideration.

Answers to the specific questions raised in your letter of May 18, 1990 will be forthcoming shortly. Please do not hesitate to call on me if I can be of assistance regarding any aspect of this issue.

Sincerely,

Richard Schmalensee

Enclosure

The Honorable Wendell H. Ford
Chairman, Subcommittee on Energy Research
and Development
Committee on Energy and Natural Resources
Unites States Senate
364 Dirksen Building
Washington D.C. 20510-6150

Proposed WEPCO Language

Sec. XXX APPLICABILITY OF NEW SOURCE REVIEW TO EXISTING ELECTRIC UTILITY STEAM GENERATING UNITS.

(a) Applicability of New Source Performance Standards--No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for purposes of Section 111, provided such change does not increase the maximum hourly emissions of any pollutant regulated under the section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(b) Applicability of Part C of Title I --

(1) Pollution Control Projects--For purposes of Part C, no physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification of the source for a specific regulated pollutant, provided that the change constitutes a pollution control project at that unit and does not increase maximum hourly emissions of that pollutant above past maximum hourly emissions of that pollutant at that unit; or

(2) Pollution Control Projects with Contemporaneous Changes--For purposes of Part C, no physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification of the source for a specific regulated pollutant, provided that the change is part of a pollution control project at that unit and

(A) is accompanied by contemporaneous physical or operational changes to that unit, that do not exceed 20 percent of the total cost of the project; and

(B) the change does not increase maximum hourly emissions of that pollutant above past maximum hourly emissions of that pollutant. For a unit subject to section 407, immediately following the changes, the unit shall be required to meet the nitrogen oxide emission limitation specified for that boiler type pursuant to section 407. In the event that the change precedes the establishment of nitrogen oxides emissions limitations for that boiler type, pursuant to section 407,

the unit shall be required to meet the applicable emission limitation upon the date required by the regulation; (i) for an existing electric utility steam generating unit not subject to section 407, immediately following the change, the unit shall be required to meet the nitrogen oxide limit equivalent to the limit achievable using "low-NOx burners."

(3) Except as provided in (b)(2), in the event that the maximum hourly emissions of any regulated pollutant increase, the source is subject to the requirements of subsection (c) for the pollutant.

(c) Nonpollution Control Projects and Pollution Control Projects in Nonattainment Areas--Except for a unit that is subject to the provisions of subsection (b), no physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for purposes of Part C or Part D, provided that such change does not result in a significant net increase in representative actual annual emissions of any regulated pollutant at the source in the case of Part C and of any criteria pollutant in the case of Part D.

(d) System-wide Netting--

(1) The operating company may, for purposes of subsection (c) of this section, elect to calculate its representative actual annual emissions (A) on a statewide basis, where EPA is the permit issuing authority in the State and thes tate agrees, or (B) on a system basis, where EPA is the permitting authority in one or more States in which the operating company owns electric generating units, provided all affected States agree.

(2) Any State permitting authority may allow actual annual emissions in both representative periods to be (A) total operating company emissions within the State, (B) with the agreement of the owners of all other electric generating units with the State, total emissions within the State, or (C) with the agreement of any other States in which the operating company owns electric generating units, total operating company emissions.

(e) Modeling Requirements--Nothing in this section shall authorize an increase in emissions which causes or contributes to a violation of a national ambient air

quality standard, PSD increment, or visibility limitation. Any physical or operational change at a source subject to subsection (b) of this section that results in an increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purposes of Title I, if any, which the Administrator determines is reliable, may be required to perform an air quality impact analysis, whenever the Administrator has reason to believe that the increase will cause or contribute to a violation of any ambient standard, PSD increment, or visibility limitation. The Administrator shall have the authority under this section to gather any necessary information, including requiring the source to conduct modeling, if necessary.

(f) Nitrogen Oxide Control Requirements---

(1) Any modification, as defined in section 169(2)C), at an existing electric utility steam generating unit subject to section 165 shall be deemed to satisfy the technology requirements of section 165(a)4 for nitrogen oxides if it meets the following:

(A) For a unit subject to a requirement promulgated pursuant to section 407, immediately following the modification, the unit shall be required to meet the nitrogen oxide emission limitation specified for that boiler type pursuant to section 407. In the event that the modification precedes the establishment of nitrogen oxides emissions limitations for that boiler type pursuant to section 407, the unit shall be required to meet the applicable emission limitation upon the date required by the regulation.

(B) For an existing electric utility steam generation unit not subject to section 407, immediately following the modification, the unit shall be required to meet the nitrogen oxide limit equivalent to the limit achievable using "low-NOx burners."

(2) Any State or local permitting authority shall retain the right to impose more stringent limitations for control of nitrogen oxides.

(g) Definitions--For purposes of this section,

4

(1) "Pollution Control Project" means any physical change, or change in the method of operation, at an existing electric utility steam generating unit for purposes of reducing emissions from such unit in order to comply with Title V. Such changes are limited to:

(A) Installation of conventional or innovative pollution control technology, including but not limited to conventional and advanced flue gas desulfurization, sorbent injection for SO2 and NOx controls and electrostatic precipitators; and

(B) Physical changes, or changes in the method of operation, to accommodate switching to fuel which is lower in sulfur content than the fuel used prior to the change, including natural gas or coal re-burning, co-firing of natural gas and other fuels for the purpose of controlling SO2 or NOx emissions; and

(C) Clean coal technology demonstration projects conducted under Title II, section 101(d) of the Further Continuing Appropriations Act of 1985 (section 5903(d) of title 42 of the United States Code), or subsequent appropriations, up to a total amount of $2,750,000,000 for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency.

(2) "Representative Actual Annual Emissions" means:

(A) for the period prior to a physical change or change in the method of operation of a unit, the average rate, in tons per year, at which the unit actually emitted the pollutant during the two-year period which precedes the change, provided that the Administrator shall allow use of a different consecutive two-year period within the 5 years before the change, where the Administrator determines that such a period is more representative of normal source operations; and

(B) for the two-year period after a physical change or change in the method of operation of a unit, (or different consecutive two-year period within 10 years after that change, where the Administrator determines that such

period is more representative of normal source operations), the projected average rate in tons per year at which the source is projected to emit a pollutant, and considering the effect any physical or operational changes have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future capacity utilization, the Administrator (i) may consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with State or Federal regulatory authorities, and compliance plans under the Title V of this Act, and (ii) shall exclude that portion of the increased rate of utilization, if any, due to factors unrelated to the physical or operational change, including an increase in projected capacity utilization equal to the rate of electricity demand growth for the utility system as a whole.

(h) EPA Guidance--Within 24 months of enactment of this section, the Administrator shall, after notice and the opportunity for public comment, issue guidance for use by permitting authorities in determining criteria under which various refurbishment projects would be considered routine or nonroutine.

NOTE: References to "section 407" refer to S.1630. Other section numbers refer to the current Clean Air Act.

COUNCIL OF ECONOMIC ADVISERS
EXECUTIVE OFFICE OF THE PRESIDENT
WASHINGTON

MEMBER OF THE COUNCIL

September 11, 1990

Dear Chairman Ford:

This is in response to your letter of May 18, 1990 regarding the WEPCO issue and my testimony of May 8, 1990. Answers to the specific queries posed in the attachment to your letter are enclosed. These answers are most usefully considered in the context of the legislative language developed in close collaboration with EPA and DOE and forwarded to you under separate cover on July 23.

One point of clarification is in order to avoid any chance of misunderstanding. Although technically the addition of a new unit to an existing source is considered a modification under Prevention of Significant Deterioration provisions of the Clean Air Act, the changes to the modification provision proposed in our July 23 language are not intended to apply to such projects. Such projects should still be subject to full new source review.

I apologize for the delay in replying to your questions. Please do not hesitate to call on me if I can be of further assistance regarding any aspect of this issue.

Sincerely,

Richard Schmalensee

Enclosure

The Honorable Wendell H. Ford
Chairman, Subcommittee on Energy Research
and Development
Committee on Energy and Natural Resources
United States Senate
364 Dirksen Building
Washington, D.C. 20510-6150

RESPONSES FROM RICHARD SCHMALENSEE (CEA)
TO SENATOR FORD'S QUESTIONS
ON ADMINISTRATION TESTIMONY REGARDING S. 1848

1.a While ICF's "high impact case" estimate of the additional cost of compliance under acid rain legislation due to WEPCO seems very unrealistic, would you agree that ICF's "low impact case" cost estimate of $1 billion in additional costs is reasonable? Please explain your answer.

To date, WEPCO is one of the few utility plants to trigger the modification provisions at existing units. However, given the forecasted reliance on refurbishment in the electric utility sector clearly more WEPCOs are in store. To be sure, given the case-by-case application of the PSD program, its precise future impact is difficult to estimate. The UARG study is based on explicit out-of-model assumptions about how broadly the modification rule would apply to utility boilers. The Administration believes that the low impact case assumptions concerning the types of plants that might be subject to the modification rule are plausible. This case assumes that roughly 15 gigawatts of existing coal-fired utility capacity would be subject to new source review regulations. However, while the assumptions regarding the incidence of the modification rule are plausible, the cost and emission reduction estimates in the UARG low impact case may be both too high for several reasons.

The UARG low impact scenario assumed that only those coal-fired power plants with historically poor performance and

availability would trigger the modification provisions of PSD. The low impact scenario also assumed that all oil-capable units which were predicted to switch to natural gas in EPA's base case forecast, would be affected--meaning, potentially subject to PSD as a modification.

Several factors suggest that the cost estimates in the UARG study may be high. First, the UARG study assumes that all capacity that would be affected by the PSD provisions is required to meet the NSPS provisions, that is, to achieve the same emissions rates that would be required of an entirely new unit. This clearly is not the case. Apparently, the basis of this assumption was the WEPCO case in which three of the five units were subject to NSPS as well as to the PSD provisions. Some refurbishment projects may in fact lead to an increase in maximum hourly emissions, and thus an NSPS determination. Of course, the extent to which projects fall into this category would depend on the procedure for determining baseline maximum hourly emissions, an issue addressed in our legislative proposal, and the nature of a particular project involved. However, those projects that did not increase maximum hourly emissions would be subject only to the PSD provisions.

Second, the UARG study assumed that the only technology available to meet the NSPS would be wet limestone scrubbing--the most expensive of the retrofit SO_2 removal technologies

available. In reality, it is likely that less expensive removal technologies might be used to "net out" of NSPS, e.g., dry scrubbing and sorbent injection. Moreover, if a plant were to install wet scrubbing to maximize SO_2 reduction in order to create allowances for use in the acid rain trading program, those incremental costs should not be attributed to the NSPS or PSD compliance requirements.

Third, since both the Senate and House bills repeal the percent reduction requirement in the NSPS provisions, no technology at all may be needed to net out of any potential increases in hourly SO_2 emissions. Units potentially subject to NSPS as modifications would be free to switch to lower sulfur coal, oil, or gas to keep hourly emissions from increasing, although not without cost.

It also appears that the UARG estimates of costs and emission reductions for NO_x controls at coal-fired plants under the modification rules are somewhat high, although the situation here is less clear than for SO_2. For NSPS purposes, the installation of low-NO_x burners, which both the Senate and House bills require at all wall-fired boilers and tangentially fired boilers, could be used to avoid an increase in hourly emissions. For cyclone and wet bottom boilers, however, it is not clear what options are available to keep hourly NO_x rates from increasing. For PSD purposes, where the relevant tests involve annual

emissions, it is not clear what measures could be applied to reduce NO_x emissions at a unit where low NO_x burners are already in place and further investment in a pollution control project that would lead to greater use of the facility under an environmentally sound dispatch plan is contemplated. However, only the costs associated with netting out emissions are appropriate to a cost analysis of the modification rule.

The UARG low-impact assumption for oil-capable boilers seems to be reasonable--that is, oil-fired boilers adding the capability to burn natural gas were assumed to net out of PSD by reducing emissions at the plant to offset any potential increases in emissions.

Taking a broader perspective on your question, we can look at the situation from two perspectives. First, how does the planned acid rain program affect PSD/NSPS compliance costs and emission reductions? Inversely, how does the existing PSD/NSPS program affect the costs/operation of the planned acid rain program?

The impact of the acid rain program on new source review compliance costs reflects two conflicting forces. On the one hand, compliance actions taken to meet the requirements of the acid rain program would be likely to increase the number of existing facilities facing new source review as compared to a

"business as usual" scenario. However, the salability of sulfur dioxide emissions allowances, freed up by NSR-mandated reductions in sulfur dioxide emissions, and the fact that some investments can satisfy both NSR and acid rain program requirements tend to work in the opposite direction.

Despite the problems noted above, the UARG study provides an illustration of how the presence or absence of an acid rain program might affect PSD program costs. UARG believes that the incremental cost of the PSD program without an acid rain program ranges from $1.1 billion to $9.5 billion in 2010. With an acid rain program, PSD costs range from $1.0 billion to $7.2 billion. However, the incremental NO_x and SO_2 emission reductions from the PSD program are significantly lower with the acid rain program in place than without it. For NO_x, emission reductions with PSD alone range from 0.2 to 1.3 million tons from the baseline. With an acid rain program in place, the incremental reductions from PSD are 0.1 to 0.4 million tons. Furthermore, with an acid rain program in place, PSD has no impact on aggregate SO_2 emissions.

Taking the inverse perspective, the additional costs and uncertainty imposed pursuant to any triggering of the modification provisions of the Act, as presently implemented, could easily dissuade utilities from engaging in some sound projects that otherwise would have been undertaken as part of the

low-cost acid rain compliance strategy. Attempts by utilities to work around the present modification rule process would thus tend to raise the actual cost of acid rain compliance. Administration analyses of acid rain compliance costs do not account for these impacts, because they are highly dependent on case-by-case conditions.

The strong interaction between the new source review and acid rain programs suggests the advisability of revising the former, along the lines suggested in the Administration's WEPCO proposal, while enacting the latter.

1.b. The ICF study indicates that enforcement of the WEPCO policy would result in no additional sulfur dioxide (SO_2) emissions reductions over and above those that would occur under acid rain legislation and a slight reduction of 100,000 tons of nitrogen oxide (NO_x) emissions attributable to enforcement of the WEPCO policy. Do you agree with ICF's assessment?

No incremental sulfur dioxide reduction beyond the large reductions mandated under the acid rain program was forecast under the UARG study because source-specific reductions associated with triggering the modification provisions will translate into higher emissions levels at other plants, due to the operation of the national sulfur dioxide emissions trading program. The application of the modification rule can change the allocation of SO_2 emissions across plants, but not their overall quantity, which is determined by the national cap on total emissions. However, the PSD program, and the Administration's

proposal regarding its application will continue to protect local air quality values in all areas.

Given that most wall-fired and tangentially fired boilers are required to install low-NO_x burners under the acid rain program, we would be suspect of large NO_x control costs or emission reductions associated with the application of the modification rule on top of that program. The UARG estimate of incremental NO_x reduction estimates apparently reflects the high degree of control required under the acid rain program, which leaves few situations where further control would be necessary or possible under new source review. Indeed, the UARG study assumes more stringent and costly additional NO_x controls than would likely be installed in most cases.

The comments presented above apply specifically to the "low impact" case. A higher level of NSR incidence would, of course, tend to offset the influences tending to reduce total cost cited above.

1.c. Assuming ICF's assessment of additional NO_x emissions reductions attributable to EPA's enforcement of the WEPCO policy to be true and also assuming ICF's "low impact case" cost estimate to be true, would the additional NO_x emissions reductions be cost effective under the criteria that the President has stated for his approval of clean air legislation that might be passed by the Congress?

The UARG low-impact cost estimate is $800 million (year 2000) to $1 billion (year 2010) above the costs of the acid rain program. The incremental emissions reductions estimates for this case are 100,000 tons of NO_x. Overall SO_2 emissions would be unaffected by virtue of the acid rain program. However, as noted above, the UARG cost estimates may overstate actual costs -- NSPS will not apply in all cases, lower cost technologies may become available, and the value of sulfur dioxide allowances may provide a significant cost offset. Moreover, facilities in some cases have the ability to avoid triggering the modification rule by implementing limited controls. Such behavior may lower <u>both</u> costs and NO_x emissions reductions.

Estimated NO_x reduction costs for the Administration proposal and the House and Senate bills fall in the $200 to $400 per ton range.

1.d. Should the NO_x emissions reduction program in Section 407 of S. 1630 become law, would compliance with Section 407 achieve the NO_x emissions reductions that might be achieved by enforcement of the WEPCO policy?

The acid rain title of the proposed Clean Air Act Amendments is projected to achieve a reduction in NO_x emissions from baseline levels of approximately 2.0 million tons by the year 2000 according to the latest ICF analysis of the Senate and House bills. (The House requirement for a 2.5 million ton reduction is met by substituting extra SO_2 reductions for 0.5 million tons of

NO_x reductions under the SO_2 for NO_x trading provisions of the House bill.)

In the absence of the acid rain program, the UARG study estimates reductions in NO_x emissions from baseline levels of between 0.1 and 0.6 million tons by the year 2000 pursuant to the application of the current WEPCO policy. As noted above, there are several reasons why the UARG study probably overstates both the emissions reductions and costs of the modification rule.

The focus of the acid rain program is on aggregate emissions, while the PSD program is designed to protect local air quality objectives. Significantly, the Administration's proposal regarding the application of new source review to units subject to the acid rain program is designed to ensure that local air quality values are protected, while providing an appropriate degree of flexibility and predictability to utilities in planning their compliance with our ambitious program to achieve very large reductions in emissions that contribute to acid rain.

1.e. Has the Council of Economic Advisers or any other office within the Administration performed its own analysis of: (a) the additional costs of compliance with acid rain legislation that might be attributable to EPA's enforcement of the WEPCO policy; and (b) additional emissions reductions over and above those that would occur under acid rain legislation that might be achieved as a consequence of the enforcement of the WEPCO policy? If the answer is yes, please provide copies of such analyses.

No government agency has performed an independent study of the type outlined in your question. As noted in our response to question 1.a., all Administration acid rain studies have assumed that compliance decisions are made without regard to the application of the modification rule. As our answer to question 1.b. indicates, we would not expect the application of the WEPCO policy, which focuses on emissions at the plant level, to reduce aggregate SO_2 emissions. Our answers to 1.a. and 1.b. explain why the incremental NO_x reduction identified by UARG (0.1 million tons in the low impact case) is probably an overestimate.

1.f. Has the Council of Economic Advisers or any other office within the Administration analyzed the compliance cost and emissions reduction impacts of the principles for a legislative resolution of the WEPCO issue outlined in your testimony?

No.

2. In your prepared written testimony at pages 7 and 8, you discuss the extent to which the Senate and House clean air bills address the WEPCO issue. In reference to Section 415(e)(3) of S. 1630, the Bumpers-Breaux-Bingaman Amendment, you state: "Some have suggested that this presumption [regarding capacity utilization] may be easily rebutted by either the utility's own announced plans for compliance with the acid rain program or by consideration of the likely impact of a project on utility dispatch plans." Do you view the presumption in Section 415(e)(3) as easily rebutted? Please explain.

For sources installing pollution control hardware, or switching from oil to natural gas as part of an SO_2 control program, we would expect the capacity utilization of the unit to

increase after installation of the hardware, or after the conversion to gas. Our expectation is based on economics. It is reasonable to expect utilities to dispatch generating units based on lowest variable costs. With respect to scrubbers, they generally are less cost-effective at controlling SO_2 than fuel switching, but they are capable of achieving much greater SO_2 reductions at a given unit. Moreover, their variable costs are a small fraction of their overall costs. For example, ICF's scrubber costs used in analyses for EPA include, for a 2.5 percent sulfur coal and in 1986 dollars, capital costs of $192/kw, fixed O&M costs of 6.18 $/kwyr, and variable O&M costs of 1.37 mills/kwhr. Assuming a 65 percent capacity factor, to enable comparison, the variable costs work out to about 23 percent of total scrubber costs. In this case, scrubber costs are about $325/ton of SO_2 removed, but the variable scrubber costs are only $75/ton of SO_2 removed. This variable cost is much less than the cost of low sulfur coal, which varies by region, but generally has a cost effectiveness ratio of $200-$300/ton of SO_2 avoided (almost all of which is a variable cost). As a result, all other factors being equal, a utility with a scrubber equipped unit and a unit burning low sulfur coal will generally prefer to run the scrubbed unit more, because its variable costs are less.

Similarly, for the oil-fired generator converting to natural gas, the conversion will likely be based on economics. In other

words, it will be converted only if it is cheaper, considering both fuel prices and the cost of meeting SIP's and acid rain regulations, to operate on gas, rather than on oil with emission controls. Assuming there remain some oil-fired units in the utility system, the utility would generally prefer to utilize the converted unit more, and other oil-fired units less.

The utility's dispatching intentions must be made clear to the permitting authority because of provisions in §408(c) and (d) of S. 1630. These provisions require owners and operators of units subject to Phase I or Phase II limitations to submit permit applications and proposed compliance plans for review and approval by the permitting authority. Because compliance is based on annual emissions of SO_2, not hourly rates of emission, it will be essential for the utility to explain not only the hourly emission rate of a unit, but also the level of expected capacity utilization of the unit. Given that historical levels of capacity utilization are a matter of public record, any change in utilization rates before and after pollution controls are installed will be self-evident. This is the basis for the statement in my testimony suggesting that utilities will themselves rebut the constant capacity factor presumption.

3. In your prepared written testimony at page 9, you state that "the administration supports a broad, generic legislative resolution [of the WEPCO issue] that has seven basic elements."

A. Why is this a legislative proposal? Why could you not accomplish the same result by administrative action under current law?

As stated in my testimony, much of what the Administration seeks to accomplish through this legislative proposal could be accomplished by administrative action under current law. However, a clear statement in law will provide a firmer foundation for utilities to plan and implement cost-effective long-run strategies to achieve the very large required reductions in emissions that contribute to acid rain while continuing to maintain capacity and reliability in the electric supply system. Relying solely on administrative action will increase the uncertainty faced by the utilities that already have to implement a number of technically complex and costly revisions in their operating procedures to comply with the new Clean Air Act.

Other adjustments needed to take account of the interaction between the application of the existing modification rule and the acid rain program can only be addressed through legislation. The Senate and House share this concern, as reflected in the provisions of Sections 415 and 512 of their respective bills. The Administration seeks to provide an appropriate degree of flexibility and predictability to utilities subject to the acid rain program. It recognizes that the acid rain program -- with its unique emissions cap and tradable allowances provisions --

creates a special set of conditions that necessitate changes in the application of the modification rule.

With reference to the proposed legislative language submitted on July 23, let me highlight the provisions that could be undertaken administratively under current law and those that would require a legislative change:

a. NSPS Emission Increase Calculations - EPA's current regulations provide for a comparison of the hourly emission rate, just prior to a physical or operational change, with the hourly emissions following the change to determine whether or not emissions will increase as a result of the change. The proposed legislation would use as a baseline the highest hourly emissions level achievable any time during the 5 years prior to the change. The EPA could accomplish the same result through rulemaking.

b. Pollution Control Projects - EPA could through administrative action exclude certain pollution control projects from NSPS and PSD review. Under current law, however, it would be difficult to consider for PSD purposes the change only with respect to that pollutant for which there is an increase in potential emissions. No basis for such a distinction exists in the current statutory provisions relating to PSD review. Further, EPA could through rulemaking make certain changes to the method of calculating emissions increases under PSD. Changing to

a maximum hourly emissions test as set forth in our legislative proposal, or to the potential emissions test in the House bill, however, would be difficult under current law.

c. Safe Harbor Provision - Current EPA regulations exempt routine projects from new source review. EPA can issue guidance or regulations clarifying what types of projects would be considered routine and thus not subject to new source review. The safe harbor provision, however, would broadly expand administrative exemptions to the statutory requirements in order to exclude nonroutine physical renovations that were complementary to and contemporaneous with a pollution control project, so long as their cost did not exceed 20 percent of the cost of the total project. It provides a mechanism through which utilities can themselves determine the applicability of new source review to a set of physical or operational changes intended to control pollution plus other complementary, contemporaneous renovations that would be needed to take full advantage of this pollution control investment to comply with the acid rain program. Sources wishing to use the safe harbor must also implement NO_x controls under Section 407 on an accelerated basis. Despite the importance of the safe harbor in promoting a smooth implementation of emission reduction mandates under the acid rain program, a reviewing court likely would find it to be inconsistent with the present statute if implemented through rulemaking. See WEPCO v. Reilly, 893 F.2d 901, 909 (7th Cir. 1990).

d. Systemwide Netting - The proposal to allow, but not require, the relevant permitting authority to use systemwide netting among various utility sources to calculate whether an emissions increase will occur for new source review purposes could not be accomplished under current law. The definition of "source" under current law cannot be construed so broadly as to encompass facilities that are not within a single plant.

e. Modeling - The modeling provision could be adopted through administrative action.

f. Generic NO_x BACT Determinations - Under current law, a BACT determination must reflect the maximum reduction in emissions achievable on a case-by-case basis, taking into account individual characteristics of the particular source and can be no less stringent than the NSPS. See CAA §169(3). Therefore, a finding that a particular NO_x control technology or emission limit constitutes BACT for an entire source category could not be made through administrative means.

g. Nonpollution Control Projects - The Administration proposal would adopt an "actual-to-actual" methodology for calculating emissions increase for purposes of new source review under Parts C and D of Title I. It would also exclude emission increases due to demand growth and other factors unrelated to the modification, since such emissions increases would occur even if

no modification were undertaken. These changes could be implemented through rulemaking.

B. Should S. 1630 as written become law, could the Administration's proposal for resolution of the WEPCO issue be implemented by administrative action? If not, do the WEPCO provisions in S. 1630 preclude administrative implementation of the Administration's proposal?

The Administration's legislative proposal differs from the Senate bill in three key respects. The Senate bill would subject a substantial group of pollution control projects to PSD and NSPS review, since it incorporates an emissions increase test in which the projected increased utilization of plants with new pollution controls to meet acid rain objectives would trigger new source review. The Administration proposal would exempt pollution control projects from NSPS and Part C requirements, provided that maximum hourly emissions do not increase, and would not apply new source review requirements for those pollutants for which maximum hourly emissions decrease or remain constant. This maximum hourly increase test will provide for smoother compliance with the emission reduction mandates of the acid rain program.

Also, there is nothing comparable to the Administration's "safe harbor" provision in the Senate bill. This provision ensures that whatever latitude is afforded to pollution control projects in all of the bills could not be offset due to the

triggering of NSR by other complementary, contemporaneous renovations valued at up to 20 percent of the total project needed to take full advantage of a pollution control project that does not increase maximum hourly emissions. Such a provision is necessary to avoid discouraging compliance strategies designed to use clean plants with pollution control projects more intensively and dirty plants less intensively.

A third difference is that the Senate bill exempts repowering projects from NSPS-reconstruction provisions. The Administration's proposal would generally subject these projects to NSPS. Other differences also exist, such as the provision for systemwide netting of emissions in the new source review process to allow the regulatory authority, at its option, to take into account the reduction in emissions at other facilities which will occur as utilities reallocate their generation load to make greater use of units equipped with pollution control projects.

The answer to Question 3.a. already identifies the components of the Administration proposal which could be undertaken administratively under current law. The WEPCO provisions of S. 1630 would, to the extent that they provide statutory guidance, preclude some actions that are administratively feasible under current law. For example, it may not be possible to exclude demand growth from the rebuttable presumption test under Section 415(e)(3). Overall, the WEPCO

provisions of S. 1630 do not provide nearly as many guaranteed options for utilities to implement environmentally sound compliance and system planning options at the lowest possible cost.

C. Should H.R. 3030 as reported by the Committee on Energy and Commerce become law, could the Administration's proposal for resolution of the WEPCO issue be implemented by administrative action? If not, do the WEPCO provisions in H.R. 3030 preclude the Administration's WEPCO proposal?

[Because the House passed its version of the Clean Air Act subsequent to the issuance of these questions, we have responded to this question based on the House Bill as passed.]

Section 512(b) of the House bill provides that no physical or operational change in a unit for purposes of reducing emissions in order to comply with the acid rain title shall be treated as a modification for purposes of Section 111 (NSPS) or Part C of Title I (PSD) provided potential emissions do not increase. The Administration's proposal for pollution control projects (other than CCT projects) is similar to the language contained in Section 512(b). However, because there is no safe harbor provision in the House bill, the extent of usable relief to pollution control projects may be limited.

Section 515 directs the Administrator to issue regulations to facilitate temporary and permanent CCT projects. In

determining whether or not an emissions increase would occur for permanent CCT projects, Section 515(c) directs the Administrator to compare pre-project actual emissions with projected future emissions projecting a future 70 percent capacity utilization factor. Under Section 515 of the House Bill, fewer CCT projects would likely be exempt from NSPS and PSD review because the emissions increase calculation is actual-to-projected actual, assuming 70 percent capacity, while the Administration's proposal uses a maximum hourly test for CCT projects.

Repowered sources are also afforded certain relief under Section 508(c) of the House Bill. These sources are exempt from any NSPS. They are also exempt from the new source requirements of Part C or D if projected emissions do not increase over past actual emissions. As with CCT projects, future emissions are to be projected using a 70 percent capacity factor. (Repowering is defined in Section 502(c)(14).) In some cases, repowered projects would qualify as pollution control projects under the Administration's proposal. The Administration's proposal would not, however, exclude these projects from NSPS reconstruction rules. In other cases, they may be treated as nonpollution control projects.

These are the only House provisions that relate directly to the Administration's proposal. Since both the House and Administration proposals operate via exclusion, all or parts of

35-212 0 - 90 - 7

these proposals could coexist if both were legislatively authorized. With respect to administrative steps, other actions identified in response to question 3.a. could be undertaken to the same extent as identified in the response to that question, provided that they were not precluded by new statutory language.

3.* [Note that this is the second question labeled as "3" from the questions submitted].

In your prepared written testimony at page 11, you state: "However, units seeking to take advantage of this provision would be required to meet the NO_x reduction limits required by the applicable final rule, if any, issued under Section 407(b) as a part of the total project."

A. What if a powerplant undertakes nonroutine physical or operational changes prior to the issuance of an applicable final rule under Section 407(b)?

If a powerplant undertakes a nonroutine physical or operational change under the "safe harbor provision" prior to the issuance of an applicable final rule under Section 407(b), the unit would be required to meet the applicable emission limit upon the date required by the rule that is ultimately issued. Until that time, the unit must meet an emission limit equivalent to that achievable using low-NO_x burners on that type of unit. This is reflected in Section (b)(2)(B) of the proposed legislative language submitted to you on July 23.

B. Under Section 407(a), an affected unit for purposes of SO_2 reduction requirements shall be an affected unit for purposes of the NO_x limitations set forth in Section 407. Does this mean that the net effect of the above-quoted sentence is to accelerate the applicability of NO_x reduction requirements for "utility pollution control projects?"

Under the legislative proposal, any unit installing a pollution control project and undergoing contemporaneous non-routine physical or operational changes costing up to 20 percent of the total cost of project would be subject to the NO_x requirements as applicable to it at the time of the project. In some instances, this may accelerate the time for compliance with the NO_x requirements. However, the schedule for compliance with Section 407 requirements would not be affected for projects that do not take advantage of the "safe harbor" provision.

C. What do you intend by the term "this provision" in the above-quoted sentence? Do you intend to refer only to the provision governing units that make [modifications] which are not entirely "utility pollution control projects" (i.e., the units discussed in the paragraph in which the above-quoted sentence appears)? In the alternative, do you intend to refer to the provision governing all "utility pollution control projects" including projects in which all changes are made entirely for purposes of reducing emissions in order to comply with the acid rain title of clean air legislation?

The phrase "this provision" at page 11 at my testimony refers to the "safe harbor" provision. The "safe harbor" provision (as outlined in Section (b)(2) of the legislative language) applies to projects that are pollution control projects and also include some other contemporaneous change. The cost of these other changes may not exceed 20 percent of the total cost of the project. "Pollution control projects" which incorporate

no other changes, and do not need the "safe harbor" must, as in the House bill, satisfy only the emissions increase test, i.e., that maximum hourly emissions do not increase.

4. Physical or operational changes which improve power plant efficiency reduce fuel consumption per unit of energy output and correspondingly reduce emissions per unit of energy output. In view of this, would the term "utility pollution control project" include nonroutine physical or operational changes intended to improve powerplant efficiency if such changes were undertaken as part of a utility's strategy for compliance with the acid rain title of legislation to amend the Clean Air Act?

Our proposal contemplates that a "Pollution Control Project" would consist of those physical and operational changes outlined in Section (g)(1). There is no specific provision for investments in powerplant efficiency as such. Of course, under the safe harbor provision, a limited value of complementary, non-routine physical or operational changes can be treated as part of a pollution control project.

5. From your testimony at page 11, it would appear that whether a power plant modification qualified as a "utility pollution control project" would depend on the intent of the powerplant operator.

   A. How would this standard apply to powerplant modifications that reduce emissions subject to the acid rain title of clean air legislation, but which are undertaken prior to the date that emission reduction deadlines take effect? What about projects undertaken pursuant [to] emissions reduction requirements under State law?

Power plant modifications that reduce emissions subject to the acid rain title of the clean air legislation would qualify as

"utility pollution control projects" and be treated as such once the legislation becomes law. This would apply to any qualifying project, as of the date the legislation becomes law, regardless of when the emission reduction is undertaken. The legislation considers a "utility pollution control project" to be those changes implemented for the purpose of complying with the acid rain title. It does not cover changes made pursuant to State law.

B. If such modifications did not qualify as "utility pollution control projects," this would constitute a penalty against early emissions reductions. Would there be any legal or public policy justifications for such a result?

There is no public policy rationale for excluding projects undertaken prior to the date that emission reduction deadlines take effect from the category of "utility pollution control projects." Indeed, any such exclusion would appear to contemplate significant assistance from supernatural forces in executing pollution control projects at the instant they must be in place to meet statutory requirements.

6. In your prepared written testimony at page 10, you state that "a project that did not increase annual emissions of a source above the levels used in establishing the baseline or in determining increment consumption would be considered to meet annual PSD requirements for that source without any further showing."

A. Is this a restatement of existing policy under the PSD program or is it intended to be a new formulation of policy under the PSD program?

35-212 0 - 90 - 8

This is a statement of policy to accommodate the proposed change in the method of calculating emissions for pollution control projects. The legislative language of the Administration proposal provides that if the source will not increase its actual emissions over the level of emissions that was used in the most recent air quality impact analysis, the source's contribution to the consumption of PSD increment is unchanged, and no further modeling is needed, unless the Administrator determined that the earlier modeling was unreliable or otherwise concludes that an additional showing is needed to protect air quality values.

B. Under this formulation, how would an "increase in annual emissions of a source" be measured?

An increase in representative actual annual emissions would be based on a comparison of 1) the average rate in tons per year at which the source actually emitted during the two years preceding the proposed change (or some other representative 2-year time period within the previous 5 years), and 2) the projected average rate in tons per year at which the source will emit a pollutant, based on projected future capacity utilization for the 2 year period following the change (or some other 2-year period within 10 years after the change), but excluding increases in the rate of utilization due to systemwide demand growth and other factors unrelated to the physical or operational change.

7. In your prepared written testimony at page 10, you state that "part D review and permitting requirements would also be triggered by any nonroutine physical change, including pollution control projects, that resulted in a net increase of pollutants in a nonattainment area that would exacerbate exceedence of air quality standards. The net increase determination would be based on a comparison of before and after emissions across representative periods."

   A. What would constitute a "net increase of pollutants...that would exacerbate the exceedence of air quality standards"? For example, would an increase in NO_x emissions "exacerbate the exceedence of air quality standards" in an ozone nonattainment area?

The existing new source review regulations for new and modified major sources specify certain significance levels for each of the various criteria pollutants. In a nonattainment area, an existing major source of a nonattainment pollutant proposing a nonroutine physical or operational change would exacerbate the existing violation when, as a result of the change, the net increase of that nonattainment pollutant is significant. Accordingly, in an ozone nonattainment area, a proposed project with a significant net increase of volatile organic compound emissions (i.e., 40 tons per year increase in emissions) would exacerbate the violation of the ozone air quality standard. Likewise, a significant net increase in NO_x emissions in a NO_2 nonattainment area would exacerbate the existing NO_2 violation.

The relationship between NO_x emissions and ozone formation in the individual ozone nonattainment area would be considered in

determining whether or not a significant increase in NO_x emissions would exacerbate an ozone nonattainment problem. The same concern is reflected in the attainment title of the House bill, which recognizes that there should be substitutability between NO_x reductions and HC reductions in meeting progress requirements in some areas, but not in others. Where EPA determines that ozone is not sensitive to NO_x, it would not presume that NO_x emissions exacerbate an ozone nonattainment problem.

B. How would a "net increase" in emissions be measured? Would it be on the basis of a comparison of the power plant's pre-modification and post-modification potential to emit? Would it be on the basis of a comparison of the power plant's pre-modification and post-modification actual emissions?

The basis for comparison would be essentially a comparison of the power plant's pre-modification and post-modification actual emissions, with a "net increase" in emissions measured in terms of changes in a power plant's "representative actual annual emissions." For the pre-modification period this means the average rate, in tons per year, at which the power plant actually emitted the pollutant during the 2-year period which precedes the change or any 2-year period within the 5 years prior to the change which is more representative of normal plant operation. Post-modification emissions means the projected average rate, in tons per year, at which the power plant is projected to emit a pollutant during the 2-year period following the change (or any 2-year period up to 10 years after the change) excluding

increases due to factors unrelated to the physical or operational change, such as systemwide demand growth.

C. How do you intend to define the term "representative periods?" For example, what would be the representative period for a powerplant that was shut down during the period immediately prior to its modification or a power plant whose capacity was substantially underutilized during that period due to broken or worn equipment?

The representative period is initially considered to be the 2 years prior to the change. However, the use of a different consecutive 2-year period within the 5 years before the change would be used where the Administrator determines that such a period is more representative of normal source operations. For a power plant that was shut down during the period immediately prior to its modification or a powerplant whose capacity was substantially under utilized during that period due to broken or worn parts, the most recent 2 years most likely will not be representative of normal operation. Therefore, the use of the most recent 2-year period would not apply and a different 2-year period within the last 5 years would be used to establish pre-modification emissions.

8. In your prepared written testimony at page 11, you state that "[n]onroutine physical or operational changes at existing steam electric generating units other than utility pollution control projects should not be deemed major modifications subject to the review and permitting requirements of part C and D of Title I unless they result in a net increase in annual emissions."

A. You appear to imply the necessity of a causal relationship between increases in annual emissions and the change made at the power plant. Is this what you intended?

Yes. The intent of the Administration's proposal is that increases in emissions which are due to growth and which are not directly related to the change being made at the power plant should not be considered in the calculation of an increase in actual annual emissions.

B. How would you treat a situation where an increase in emissions was not directly causally related to the power plant modification? For example, how would you treat a case where capacity utilization increased due to economic growth in a utility's service area? What about a situation where a utility's economic dispatch of the modified powerplant was altered due to a change in operating costs such as a new fuel contract?

If demand growth causes an increase in utilization of a unit which has undergone a physical change, or change in the method of operation, then the portion of the increase in demand which is unrelated to the change would not be considered in calculation of the increase in representative actual annual emissions. On the other hand, if the change results in: (a) removing bottlenecks, an outright increase in capacity or reliability, or (b) less expensive power production, which leads to greater dispatching, then the portion of capacity utilization attributable to these results from the change would be included in calculation of emissions increases. The provision for systemwide netting at the

option of the regulatory authority would be relevant to the latter circumstance.

9. In your prepared written testimony at page 10, you state that "[a]s in the Senate and House Committee bills, temporary CCT projects should be exempt from NSPS, PSD, and NA review provisions."

A. Would the change in emissions as a consequence of the removal of a "utility pollution control project" be treated the same as the change in emissions that resulted from the removal of a temporary CCT project?

Our proposal does not contemplate the removal of a "utility pollution control project." An issue may arise with respect to "reverse" fuel switching that may occur as a utility adjusts its compliance strategy by increasing emissions at some plants following a decrease at others. However, switching among fuels at a facility that is capable of burning multiple grades or types of fuel without undergoing a nonroutine physical change is, in our view, a routine change that does not trigger the modification rule.

B. If not, how would such a change in emissions be treated? For example, what if the pollution control technology did not perform up to expectations? What if the "utility control project" was installed in order to comply with phase I emissions reduction requirements and removed when the utility chose to control another power plant as part of its phase II compliance strategy?

Temporary emission control projects, even those that don't work as expected, are not subject to NSPS or NSR, as long as hourly emissions after the demonstration do not increase above

pre-demonstration levels. As for removing a Phase I control as part of a utility's Phase II plan, the likelihood of this appears to be remote. Logically, a utility would be unlikely to invest substantial financial capital in a permanent Phase I control system and then remove the system only a few years later under Phase II. If the phase I controls were part of an unsuccessful temporary demonstration, then NSR and NSPS would not apply and only the system-wide Phase II requirements would be applicable.

10. In your prepared written testimony at page 11, you state that "[a]ny nonroutine physical change in, or change in the method of operation of, an existing steam electric generating unit for the purposes of reducing emissions at that unit in order to comply with the acid rain title of the Clean Air Act should constitute, for present purposes, a "utility pollution control project."

    A. Would the term "utility pollution control project" apply to powerplant modifications made for the purposes of compliance with other provisions of amendments to the Clean Air Act? If not, please explain why.

Only modifications made to comply with acid rain provisions of the Clean Air Act Amendments would be considered a "utility pollution control project" under our legislative proposal for Title IV. Where differentiated treatment for the electric utility industry is warranted for other provisions of the bill, such as the air toxics title, appropriate provisions should be included within that title.

The acid rain program is unique in several respects. Unlike other titles affecting stationary pollution sources, it is

focused on one economic sector. In contrast to other programs, where shifts in operations among plants are largely a matter of secondary interest, the emissions trading system of the acid rain program encourages utilities to adjust their dispatch to meet their obligations in a cost-effective manner. For the trading system to operate effectively, maximum flexibility and predictability must be provided to utilities, while ensuring that local air quality values are protected as the Administration's WEPCO proposal. The acid rain program is also unique in its absolute ceiling on sulfur dioxide emissions and its comprehensive retrofit requirements for NO_x. As both the House and Senate bills recognize, these distinct features necessitate legislative changes governing the application of the modification rule to pollution control projects under this title. This does not necessarily hold true for projects undertaken pursuant to other titles of the bill in a wide variety of sectors under a variety of conditions.

B. By the term "steam electric generating unit" did you intend to exclude from the definition of "utility pollution control project" changes to combustion turbines intended to reduce emissions? Note that Title IV of S. 1630 no longer uses the term "steam electric generating unit" and that the term "unit" is defined simply as "a fossil fuel-fired combustion device."

The acid rain program under Title IV does not apply to existing simple combustion turbines and thus, our proposed changes in the application of the modifications provisions of Title I should not apply to them either.

C. Would a modification of an non-utility unit made for purposes of reducing emissions of pollutants regulated under the acid rain title of amendments to the Clean Air Act be eligible for treatment as a "utility pollution control project?" Note that under Section 410 of S. 1630 a non-utility unit may reduce emissions and opt in to the emissions allowance system under Title IV.

A non-utility unit that "elects in" under Section 410 would not be eligible for the definition of a "utility pollution control project". It would be inappropriate to extend the proposal to other industries, which are not targeted by the acid rain program or subject to its sulfur dioxide emissions cap or low-NO_x technology requirements. Unlike electric utilities, other industries are not being forced to make significant physical and operational changes.

11. In your prepared written testimony at page 11, you state that "[u]tility pollution control projects would be evaluated in terms of their impacts on maximum hourly emission rates, following current policy toward NSPS reviews. Thus, a utility pollution control project that does not increase maximum hourly emissions of any criteria pollutant compared to a representative period prior to the project should not be deemed to be a major modification subject to the review and permitting requirements of Part C of Title I."

A. What is "current policy toward NSPS reviews?" Does the above-quoted excerpt from your prepared testimony reflect such "current policy"? In WEPCO v. Reilly, the U.S. Court of Appeals for the 7th Circuit deferred to EPA's interpretation that use of a "representative" period was not required for determining baseline emissions rates under the agency's NSPS regulations. On the other hand, in its January 30, 1990, letter to the Indiana Department of Environmental Management, EPA appears to suggest that in its upcoming interpretative rule there would be some concept of a "representative" period for assessing the emissions consequences of the removal of a temporary CCT project.

The NSPS program is concerned with hourly emission rates from individual emissions units. Emission rates are calculated at maximum capacity before and after the physical or operational change to determine if there is an increase. Current NSPS rules for calculations to determine whether an emissions increase has occurred contemplate that the calculations be done based on conditions just prior to and after the physical or operational change. However, the Administrator has discretion to determine the "before" emission rate based on past performance, where, for example, the unit on which a project is contemplated has suffered damage, a common occurrence in the electric utility sector. To provide maximum predictability in utility planning to comply with the acid rain program, we believe that it is important to provide a system under which utilities can easily evaluate their NSPS limits for each unit without seeking an EPA decision. Therefore, as reflected in the legislative language provided to you, we propose that utility sources should be able to use the highest hourly emissions rate achieved during the 5 years prior to the change in determining whether a change will increase hourly emission rates.

The EPA's January 30, 1990 and March 7, 1990 letters to the Indiana Department of Environmental Management include discussion of how actual emissions before a change are determined for a

"representative period" of operation under existing PSD regulations, not NSPS. There is no explicit discussion of a representative period for "post demonstration emissions" for a temporary CCT project.

B. Is "current policy towards NSPS reviews" the same for pollution control projects as it is for other nonroutine changes?

If a project, whether pollution control or otherwise, does not increase maximum hourly emissions of an NSPS-regulated pollutant, then it is not subject to NSPS (unless reconstruction provisions are triggered, indicating a major construction of essentially new units). A pollution control project is subject to NSPS review if there is an increase in maximum capacity hourly emissions of any NSPS-regulated pollutant after the change. However, the EPA Administrator may determine, on a case-by-case basis, that the addition of a pollution control device to significantly reduce emissions of one pollutant may not be a modification even if there was a small increase in another NSR-regulated pollutant.

12. In your prepared written testimony at page 11, you state that utility pollution control projects "would include, among other changes, gas co-firing."

A. Would other modifications to accommodate switching to a cleaner fuel also count as "utility pollution control projects?" For example, what about modifications to accommodate natural gas as fuel in a unit currently fired with oil? Or what about modifications to accommodate switching from high-sulfur coal to low-sulfur coal?

The Administration's proposed language explicitly cites, within the definition of "pollution control projects," "physical changes, or changes in the method of operation, to accommodate switching to fuel which is lower in sulfur content than the fuel used prior to the change...." Such changes would include switching from oil to natural gas. However, the change must be "for purposes of reducing emissions from such unit in order to comply with Title V." Changes occurring after the enactment of the acid rain control program that met the definition established in Section (g) of the legislative proposal would generally be accepted as pollution control projects.

B. For purposes of NSPS review, would a powerplant that switched to a cleaner fuel receive credit for the reduction in its emissions rate attributable to the cleaner fuel? How does the court's holding in WEPCO v. Reilly bear on this answer?

No. Under the current NSPS for sulfur dioxide, which include a percentage reduction requirement, fuel switches are not credited when calculating emissions increases under NSPS. The method for determining emissions increases under the current NSPS directs that all operating parameters be held the same before and after the change. See 40 CFR 60.14(b)(2). Utilizing different fuels in making the determination of whether emissions would increase would be inconsistent with that directive. This issue was addressed in the WEPCO v. Reilly decision and the court

deferred to EPA's discretionary authority. See 893 F.2d 901, 913-15 (7th Cir. 1990).

13. What is your understanding of when EPA intends to release its interpretative ruling in response to the court's decision in WEPCO v. Reilly?

As noted in my May 8 testimony, EPA indicated in a letter to the Indiana Department of Environmental Management that an interpretative rule addressing WEPCO issues was under development. However, for reasons outlined in my testimony, and recognized in the Senate and House versions of Clean Air legislation, there are significant advantages to addressing these issues in a statutory setting. The focus of EPA and DOE effort has therefore shifted towards development of our legislative proposal and support of the legislative process.

14. Please provide the Committee with legislative language incorporating the principles for a legislative resolution of the WEPCO issue outlined in your prepared written testimony.

Legislative language was sent to the Committee under separate cover on July 23.

Northern Indiana Public Service Company
Corporate Headquarters / 5265 Hohman Avenue / Hammond, Indiana 46320 / Tel 853-5200 (219)

June 18, 1990

The Honorable Senator Wendell H. Ford
Chairman, Subcommittee on Energy Research
and Development
The United States Senate
Senate Russell Office Building
Washington, D. C.
20510

Dear Senator Ford:

Northern Indiana Public Service Company was pleased to have the opportunity to testify before the Subcommittee on Energy Research and Development on May 8, 1990. During the hearing, we addressed some of the regulatory impediments of natural gas cofiring and other retrofit or repowering technology. Specifically, we dealt with the United States Environmental Protection Agency's recent decision in the Wisconsin Electric Power Company's case and its progenies (WEPCO). We appreciate the opportunity to further supplement that testimony with the response to Senator Bingaman's questions. These responses are attached to this letter.

If we can be of any further assistance to you, please do not hesitate to contact me at 219-647-5252.

Very truly yours,

Mark T. Maassel
Manager, Environmental Programs

MTM:rr

attachment

860.2961.A
File: 5-EPA-CAAA-86

1. Now that you have had a chance to review the Administration's principles for a legislative resolution of the WEPCO issue outlined in Dr. Schmalensee's testimony, what are your thoughts on this proposal?

NIPSCO has reviewed the conceptual proposals presented by Dr. Schmalensee on the WEPCO issue. While it is clear that these proposals need to be further refined and developed, they represent a significant improvement in the WEPCO saga. Northern Indiana would like to offer the following specific comments on Dr. Schmalensee's proposal.

a. The Company believes that retention of the distinction between routine and non-routine physical and operational changes in utility steam electric generating units is appropriate. However, the Environmental Protection Agency (EPA) must be directed to clarify the distinction on a generic basis before specific projects are proposed. This generic clarification would allow companies to plan activities, understanding the implications of that planning. The Environmental Protection Agency's current policy of case by case determination has resulted in substantial uncertainty potentially impacting previously planned activities.

b. In providing a generic basis for determining whether a specific project is routine or non-routine, the EPA must consider the type of repair undertaken by utilities. A utility should not be punished for expensive repairs undertaken on infrequent but predictable intervals. For example, companies are required to periodically repair coal pulverizing equipment. These repairs conceivably can cost $1,000,000 or more per coal pulverizer. These repairs are made only once every two, three, four or five years depending upon such variables as the amount of coal burned in the power plant and the type of coal used. During the repair of the coal pulverizers,

other equipment in the power plant may be maintained. With the uncertainty of the current WEPCO policy, these routine, although infrequent repairs, might be grouped together to trigger WEPCO.

c. Dr. Schmalensee's proposal related to pollution control projects represents a legitimate improvement in the WEPCO policy. The EPA should not be allowed to inhibit the utility industry from installing pollution control devices or in making changes in operations to reduce pollutants. Rather, utilities should be encouraged to make these types of changes. The concept of comparing pre-change to appropriate post-change emissions rates appears acceptable, if the basis of the comparison is held constant.

d. The proposal exempting temporary CCT projects from NSPS, PSD and Non-Attainment review provisions is acceptable to us. Clearly, experimentation, development and innovation in Clean Coal Technologies are called for as part of a sound national energy and environmental policy, and this proposal advances these goals and policies.

e. Northern Indiana conceptually supports Dr. Schmalensee's proposal regarding pollution control projects. Section 512(b) of H.R. 3030, as reported by the House Committee on Energy and Commerce, is an excellent provision and should be accepted by the Senate in conference at the appropriate time. However, it and Dr. Schmalensee's proposal should be broadened slightly to cover installation of pollution control equipment or devices to comply with all titles of the Clean Air Act Amendments rather than Acid Deposition alone. Additional emission reduction devices may be required in some units to satisfy requirements for Ozone Non-Attainment requirements or hazardous air pollutants. These installations should not

trigger New Source Review requirements any more than installations necessary to comply with the Acid Deposition title.

In addition, the exemptions from New Source Review should include Part D as well as the currently covered Part C. Reductions of emissions should be encouraged no matter where they occur. It is especially significant to support emissions reductions in non-attainment areas. The State Implementation process will continue to protect human health and the environment. There is no need to penalize pollution reducing changes with the application of the provisions of Part D.

f. Dr. Schmalensee's proposal to allow contemporaneous projects during the installation of pollution control projects is based on a good understanding of utility plant operations. Utilities will repair many pieces of equipment during one concurrent outage in order to avoid repeated outages of the unit. These repairs are intended to maintain the design basis of the unit allowing safe operation and maximum efficiency from the unit. Such repairs will continue to ensure lowest cost electricity for our customers, as well as minimum emission of pollutants.

However, we are concerned that the 20% safe harbor is insufficient. For example, were a company to determine that a sorbent injection system should be installed for SO_2 control, the 20% safe harbor would not allow other required repairs. Thus, to the extent a utility could take advantage of the flexibility provided in the Clean Air Act Amendment legislation to reduce pollution at minimum cost, Environmental Protection Agency's WEPCO policy would potentially require significant expenditures for much more expensive devices. Further, we should note that the improved efficiency and safety of

a power plant with newly installed pollution control devices should be encouraged. A more efficient power plant could be operated more effectively, yet because of the pollution control device, emit no greater amounts of the controlled pollutant.

g. Northern Indiana questions the need for an air bubble type exemption. It is important to recall that at this point Congress is acting on the Clean Air Act Amendments. These Amendments will provide specific requirements for SO_2 and NO_x and particulate emissions. Congress continues to work on the final bill, and draft the agreements on emissions which will be embodied in the legislation. The EPA's WEPCO policy cannot be allowed to alter a Congressionally mandated course. The WEPCO logic, as it relates to emissions control in the Clean Air Act Amendment, need not be addressed by the WEPCO policy. Thus, the Schmalensee proposal should be clarified to indicate that emissions which do not result in exceedances of the national ambient air quality standards, nor exceed the limits imposed in the Clean Air Act Amendments, need not be addressed by Environmental Protection Agency under its WEPCO policy.

In conclusion, I would like to encourage your continued involvement in support of a full assessment of Environmental Protection Agency's WEPCO policy. This policy has serious implications for the nation's energy future. It must be fully assessed and integrated as a part of the discussion on the National Energy Strategy which have begun this year.

2. EPA's WEPCO policy subjects a power plant that makes a "nonroutine" modification to new source review under EPA's regulations.

A. What must a utility do if its power plant becomes subject to new source review?

860.2961.A
File: 5-EPA-CAAA-86

The specific steps involved in a New Source Review (NSR) for a project would depend on the source location, the federal and state regulations in place, and the characteristics of other sources in the area. Permitting requirements could also depend on discussions with the state air pollution control agency and the regional EPA office. The technical tasks required in most cases are engineering studies to quantify expected emission rate changes, to apply appropriate control technologies, and to perform mathematical modeling that determines the expected air quality impact of the modified emissions source. In some cases, ambient air quality related studies, such as impacts on soils and vegetation or visibility degradation, will also be necessary. All technical tasks performed, or not performed, will be open to public questioning before a permit can be granted.

B. How long does it take to go through new source review?

The application of New Source Review (NSR) requirements upon all "WEPCO" modifications would substantially affect projects by impacting their schedules through increased uncertainty in all phases of project permitting. Permitting is a complicated process that currently can take as few as six (6) to as many as forty-two (42) months and perhaps more. In practice, the permitting process usually takes between one to two years. The "new" approach under WEPCO would require significantly more complex reviews for applicability. Since more sources/industries conduct activities that could conceivably fall under that scenario, the number of reviews would increase dramatically. However, since the WEPCO regulatory requirements are ill defined, and current agency staffing levels are designed to meet only "true" new source reviews, it is conceivable that strict application of the WEPCO principle would significantly lengthen currently existing approval times.

C. What choices does a utility have if it finds itself subject to new source review?

As a result of this process, additional control requirements may be imposed which the company will then be required to implement. For example, companies could be required to install flue gas desulfurization (FGD) for SO_2 control or selective catalytic reduction units for NO_x control. These controls would bring the associated costs with them. The cost of an FGD system for a nominal 500 MW plant will exceed $100,000,000 with annual operating costs of approximately $10,000,000. SCR costs are less certain but will cost millions of dollars to install with levelized annual costs of millions of dollars per year.

The other option available would be netting out. Under netting out, the utility will be required to limit the operation of its power plant to some defined level. Such limitations preclude using the unit to meet future load growth or using it at design levels in emergencies when other units are unavailable. Further, the Environmental Protection Agency in imposing such limitations will, on occasion, apply the limitations to a short period of time. Such time restrictions severely impact utilities. Customer demands must be met at the instant they occur since electricity cannot yet be economically stored. For power plants, long term averages of operations do not reflect actual short term operation. Unlike many manufacturing industries, power plants cannot operate at averages across periods of time. Rather, their output increases dramatically during certain periods of the day and year to meet increased customer needs. Similarly, certain periods of the day and year have low levels of demand. Artificial restrictions imposed on operations during peak demand serve only to increase cost, decrease reliability and have little impact on the total emission of

pollutants. Thus, while netting out may be appropriate in some limited circumstances, it frequently presents insurmountable limitations.

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June 18, 1990

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Mr. Wendell H. Ford
Chairman, Subcommittee on
Energy Research and Development
United States Senate
Committee on Energy and Natural Resources
Washington, D.C. 20510-6150

Dear Mr. Chairman:

Thank you very much for providing me with the opportunity to testify before your Subcommittee. In response to the written questions from yourself and Senator Bingaman concerning natural gas co-firing and the "WEPCo" issue, I would like to submit the following for the record.

Question 1: Now that you have had a chance to review the Administration's principles for a legislative resolution of the WEPCo issue outlined in Dr. Schmalensee's testimony, what are your thoughts?

Response: The Administration's principles, as outlined in Dr. Schmalensee's testimony, represent a potentially helpful approach to the "WEPCo" problem, but there are some key points where clarification is necessary:

1. <u>"Temporary" Natural Gas Co-firing Projects</u>. Natural gas co-firing may be particularly useful as a "bridge" strategy for utilities during Phase I of the acid rain program. For it to serve this role, however, utilities have to be assured that they will not be penalized under "WEPCo" for discontinuing natural gas

use. One of the major potential obstacles to natural gas co-firing is, therefore, the application of the "WEPCo" rationale to "temporary" projects. Dr. Schmalensee's testimony recognizes the importance of this point by including as a principle that "temporary CCT (clean coal technology) projects should be exempted from NSPS, PSD, and NA review provisions. Failure to maintain this exemption would raise significant and unwarranted obstacles to the development of this important technology." Schmalensee Testimony at p. 10 (emphasis added). It is critical that natural gas co-firing be recognized as a clean coal technology for purposes of the exemption referred to in Dr. Schmalensee's testimony. If it is not, then the Administration's principles are fundamentally flawed and will continue to discourage natural gas co-firing.

2. Early Reductions Through Natural Gas Co-firing: Dr. Schmalensee's testimony appropriately acknowledges that pollution control projects, such as natural gas co-firing, should "be evaluated in terms of their impacts on maximum hourly emission rates." Testimony at p. 11. The testimony limits this principle to pollution control projects undertaken "in order to comply with the acid rain title of the Clean Air Act." Id. It is important that this limitation not be read too narrowly. Utilities may undertake natural gas co-firing as a pollution control measure

before reductions are required under the first or second phase of the acid rain program, either as a response to State law or for other reasons. These early reductions should not be discouraged, and I assume that the Administration does not intend a restrictive reading of the "in order to comply" limitation. If that assumption is not correct, then, again, I think the Administration's approach would be flawed and, in fact, environmentally counterproductive.

3. Natural Gas Co-firing in Non-Attainment Areas: Dr. Schmalensee's testimony outlines a principle that in non-attainment areas, every non-routine change, including pollution control projects, would be subject to a "net increase" test in the case of pollutants that "would exacerbate the exceedance of air quality standards." Testimony at p. 10. This is a reasonable principle, provided that it does not encompass NOx emissions in ozone non-attainment areas. The relationship between ozone non-attainment and NOx emissions is a complex one; in some instances NOx reductions may make an area's ozone non-attainment problem worse. It is not realistic to expect an individual source to conduct the sort of air quality modeling necessary to determine the regional interrelationship of NOx and VOC emissions. Instead, the focus of concern in non-attainment should be on net increases of VOC emissions. This is consistent

with the general approach to ozone non-attainment contained in S. 1630.

4. BACT and LAER for NOx: The Administration states as its final principle that if new source review is triggered, then the applicable technology standard -- BACT or LAER -- will be set at a level comparable to low NOx burners. The unstated reason for this principle is that one of the utilities' major concerns with triggering new source review has to do with EPA's recent BACT and LAER determinations for NOx emissions. The Agency has been forcing the use of an extremely expensive control technology referred to as Selective Catalytic Reduction (SCR). The Schmalensee testimony effectively acknowledges that SCR is not LAER or BACT for NOx control. That is an appropriate recognition, but it would be preferable for the Administration to address the SCR directly and in all circumstances where it arises. This is a generic new source review problem, not simply a WEPCo issue.

Question 2: You testified that you were aware of several instances where electric utilities have declined to participate in projects due to their concerns over the WEPCo issue and the risk of triggering new source review. Would you please elaborate on this and provide any documentation that you might have.

Response: Enclosed please find documentation relevant to the utility industry's reluctance to engage in activities that, because of WEPCo, might trigger new source review. It is worth highlighting in particular that this reluctance applies to natural gas co-firing projects.

Question 1: The amendments to the Clean Air Act passed by the Senate included several provisions addressing the WEPCo issue. The clean air legislation marked up by the House Committee on Energy and Commerce also includes WEPCo-related provisions.

A. Please comment on the relative merits of the WEPCo provisions that have been considered by the Congress.

B. How do these provisions compare with the principles for a legislative resolution of the WEPCo issue outlines in Dr. Schmalensee's testimony?

Response: A. Both the House and Senate versions of the Clean Air Act legislation contain provisions that will improve the current WEPCo-related problems with respect to natural gas co-firing. In the House, the principal provision is contained in Section 512(b), which states that changes made "for purposes of reducing emissions from [a] source in order to comply with this [the Acid Rain] title" will not trigger NSPS or PSD review, provided that the change does not increase emissions from the source, as measured by the potential emissions from the source before and after the change. The advantage of this

provision is that it sets a broad and reasonably straightforward rule, using a "potential to potential" emissions comparison. This avoids many of the complications, uncertainties and environmentally counterproductive results associated with the current WEPCo approach. The disadvantages are that it is limited to NSPS and PSD review -- i.e., it does not cover plants affected by non-attainment new source review -- and that the "purpose" test could be narrowly drawn. This latter point is particularly important for natural gas co-firing that occurs before a required reduction under the acid rain title. The House provisions will only achieve the full environmental benefits that I believe are intended if the purpose test is broadly construed.

In the Senate, the principal provision, at least with respect to natural gas co-firing, is contained in Section 415(e)(3)(B). This Section states that any pollution control project, including alterations that allow the use of natural gas as a fuel, will not be treated as a modification for new source review purposes, provided that there is no net increase in actual emissions. There is a presumption that such a project "will not result in an increase in the capacity utilization of the source." The merits of this approach are that it specifically includes use of natural gas as a pollution control project and that it covers both PSD and non-attainment new source review. The potential

shortcomings are that its use of the "net increase in actual emissions" test raises the very problems that created the WEPCo quagmire in the first instance. This is addressed by the "presumption" that a pollution control project will not increase capacity utilization. But the presumption is rebuttable. The key issue will be how EPA addresses the rebuttable presumption. If the presumption is viewed as easily rebutted -- which I do not believe, based on the legislative history, was the Senate's intent -- then the benefits of the Senate provision would be severely undercut. I should add that, although the Senate provision does not directly address NSPS, EPA has traditionally not triggered NSPS review for pollution control projects, and I believe that the Senate provision must be read in that light. Also, as I read Section 415(e)(1), the provisions in the section applicable to natural gas co-firing cover both the cessation of co-firing or the removal of the equipment. This is important in light of the potential temporary natural of natural gas co-firing projects.

B. At least in terms of pollution control projects, such as natural gas co-firing, the Administration's principles are similar to the concepts contained in the House and Senate bills. All three unanimously agree that a WEPCo fix is necessary for natural gas co-firing and other pollution control projects. The

Administration's principles are more elaborate than the House and Senate bills, but that is because, in part, they address changes other than those associated with pollution control projects. It is difficult to compare the Administration's approach with the House and Senate bills, since it has not been reduced to legislative language. But in general terms, it appears that the Administration would apply the House's "potential to potential" comparison for PSD and NSPS review but would apply the "net actual increase" comparison for non-attainment review purposes. The Administration's principles do not indicate what, if any, presumptions with respect to capacity utilization increase would apply.

Question 2: How are existing sources treated under EPA's prevention of significant deterioration (PSD) program and new source performance standards (NSPS)? If an existing electric powerplant did nothing to trigger new source review, what, if anything, limits the powerplant's (a) capacity utilization, (b) net emissions, or (c) emissions rate?

Response: Briefly, existing sources are affected by EPA's PSD and NSPS programs if they undertake a non-routine physical or operational change that results in an increase of emissions over a de minimis threshold. The definition of what is "non-routine" and the calculation of any actual or potential "increase" in emissions are, of course, the issues that created the WEPCo controversy. If an existing plant did nothing to

trigger new source review, then the only limits, as a matter of federal law, on the plant's capacity utilization, net emissions or emissions rate would be those contained in the applicable State Implication Plan or permits under Parts C or D of the Act.

Sincerely,

Frank Blake

Francis S. Blake

File: WEPCo

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February 7, 1990

FILE NO. 41429.000002
DIRECT DIAL NO. 202 955 1555

The Honorable William K. Reilly
Administrator
United States Environmental
Protection Agency
401 M Street, S.W.
Room 1200 West Tower
Washington, D.C. 20460

RECOMMENDATIONS ON EPA RESPONSE TO WEPCO DECISION

Dear Mr. Reilly:

On January 19, we wrote to you on behalf of the Utility Air Regulatory Group (UARG)[1] to provide additional information in support of UARG's request that you reconsider the Agency's recent new source interpretations announced in the WEPCo,[2] Detroit Edison,[3] and Ohio Edison[4] decisions. On that same day,

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1/ UARG consists of 65 individual electric utility companies that operate throughout the United States, the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association.

2/ Letter from Administrator Lee M. Thomas to John W. Boston, Vice President of the Wisconsin Electric Power Company (WEPCo) (October 14, 1988); letter from Acting Assistant Administrator Donald R. Clay to John W. Boston (February 15, 1989).

3/ Letter from David Kee, Director, Air and Radiation Division, EPA Region V, to Morton Sterling, Detroit Edison Company (December 20, 1988); letter from Donald R. Clay, Acting Assistant Administrator for Air and Radiation, to Walter McCarthy, Jr., Detroit Edison (May 8, 1989).

(Footnote cont'd.)

the United States Court of Appeals for the Seventh Circuit issued its decision in the WEPCo case.5/ As we promised in our January 19 letter, we are providing you our legal analysis of that decision and our recommendations for Agency action. See Enclosure.

Your staff's recent interpretations of the new source rules have caused much concern as to whether industry can undertake environmentally beneficial projects. For example, your staff's recent interpretations have been applied to discourage (1) clean coal technology demonstration programs, (2) refurbishment of pollution control equipment, (3) switches to cleaner, less-polluting fuels, and (4) improvements in the efficiency of facilities which reduce fuel consumption per unit of electricity produced.

As we discussed in our January 19th letter, your staff's recent interpretations are also at odds with the Administration's proposed acid rain legislation -- they could mandate the use of scrubbers by sources subject to the legislation, and eliminate flexibility to trade emissions. This could potentially quadruple the cost of this proposed legislation.6/ Finally, the decisions can block projects at facilities needed to improve reliability and productivity or to restore safe operations. For the utility industry this could lead to shortfalls in the electricity supply by the mid 1990s.7/

The Seventh Circuit's decision now gives you the opportunity to return to the traditional interpretation of the modification rules, which would avoid these adverse impacts. With respect to the prevention of significant deterioration (PSD) modification rule, the WEPCo decision categorically rejects your

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4/ Letter from Donald R. Clay, Acting Assistant Administrator for Air and Radiation, EPA, to David L. Feltner, Ohio Edison (February 22, 1989).

5/ WEPCo v. Reilly, Nos. 88-3264, et al. (7th Cir., decided January 19, 1990).

6/ ICF, Inc., "Analysis of the Potential Cost, Environmental and Energy Implications of EPA's Recent WEPCo and Greenwood Decisions" (January 1990).

7/ See January 19, 1990 letter, at 12, citing AER Study.

staff's attempt to require a comparison of "past actual" emissions with future "potential to emit" at existing facilities undergoing a physical or operational change. With respect to the NSPS modification rule, while the court deferred to your staff's interpretation, you have the authority to return to the traditional interpretation of the NSPS modification rule, and should do so in order to avoid the adverse consequences listed above.

These matters are discussed in greater detail in the enclosed memorandum. We will be in touch with you in the near future to arrange a meeting to discuss UARG's petition for reconsideration.

Sincerely yours,

Henry V. Nickel
E. William Brownell
Craig S. Harrison

Enclosure

cc: F. Henry Habicht, II, Esquire
Mr. J. Clarence Davies
William G. Rosenberg, Esquire
E. Donald Elliott, Esquire

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FILE NO.

DIRECT DIAL NO. 202-955-

January 19, 1990

The Honorable William K. Reilly
Administrator
United States Environmental
Protection Agency
401 M Street, S.W.
Room 1200 West Tower
Washington, D.C. 20460

RECONSIDERATION OF WEPCO, DETROIT EDISON,
AND OHIO EDISON NEW SOURCE INTERPRETATIONS

Dear Mr. Reilly:

On March 17, 1989, we wrote you on behalf of the Utility Air Regulatory Group (UARG)[1/] requesting reconsideration of the interpretations announced in the recent WEPCo,[2/] Detroit

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1/ UARG consists of 64 individual electric utility companies that operate throughout the United States, the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association.

2/ Letter from Administrator Lee M. Thomas to John W. Boston, Vice President of the Wisconsin Electric Power Company (WEPCo) (October 14, 1988); letter from Acting Assistant Administrator Donald R. Clay to John W. Boston (February 15, 1989). Consolidated Petitions for Review of these decisions are pending before the United States Court of Appeals for the Seventh Circuit in Wisconsin Electric Power Company v. William K. Reilly, Case Nos. 88-3264 and 89-1339.

Edison,[3] and Ohio Edison[4] decisions concerning application of Clean Air Act new source requirements to existing sources. These decisions were made either by your predecessor or by the past Acting Assistant Administrator. To our knowledge, neither you nor Assistant Administrator Rosenberg has formally endorsed them.

As indicated in my earlier letter and prior submittals to the Agency, UARG members do not believe that these interpretations (hereinafter collectively referred to as the "WEPCo interpretations") are supported by the regulatory history of either the new source performance standards (NSPS) or the prevention of significant deterioration (PSD) rules.[5] My letter today, however, focuses on the policy implications of these interpretations and summarizes the results of recently completed reports on the cost and the electric reliability consequences of the WEPCo interpretations.

3/ Letter from David Kee, Director, Air and Radiation Division, EPA Region V, to Morton Sterling, Detroit Edison Company (December 20, 1988); letter from Donald R. Clay, Acting Assistant Administrator for Air and Radiation, to Walter McCarthy, Jr., Detroit Edison (May 8, 1989). An administrative appeal of this decision is pending.

4/ Letter from Donald R. Clay, Acting Assistant Administrator for Air and Radiation, EPA, to David L. Feltner, Ohio Edison (February 22, 1989).

5/ A number of issues relating to the legal validity of EPA's approach are before the Seventh Circuit in the WEPCo case. See supra note 2. We expect a decision soon. Following that decision, we will promptly prepare the detailed legal analysis that we promised in our March 17 letter.

SUMMARY

Under the WEPCo interpretations, any "non-routine" (defined by these decisions as "infrequent") repair or replacement at a plant will require a source either to accept a "cap" on its current operations or to undergo new source review and face costly additional controls. According to your staff, the proscribed activities may include "minor component replacements and design changes as well as general rehabilitation of existing equipment."[6/] The proscribed activities also include any "alterations at a plant [that] provide an economic incentive to increase production . . . ."[7/] In addition, switching from oil

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6/ Proposed EPA Information Collection Request No. 1545.01, EPA Justification ¶ 1 (proposed request currently undergoing OMB review) (Attachment 1). See infra note 33.

7/ Memorandum from Gregory B. Foote, EPA/OGC, to William G. Rosenberg, Assistant Administrator for Air and Regulation, "Court of Appeals Decision Upholding PSD 'Actual to Potential' Applicability Rules" (November 24, 1989) (Attachment 2). The memorandum discusses a recent decision of the First Circuit which held that, when a company installs a "new" emission unit at an existing source the PSD rules require a comparison of the past "actual" emissions from the replaced unit with the future "potential" emissions of the new unit. Puerto Rican Cement Co. v. EPA, 889 F.2d 292, 296 (1989). This decision is consistent with EPA's rules which require the use of "potential" emissions for new units that have not begun "normal operations." 40 C.F.R. § 52.21(b)(21)(iv) (1988). While the memorandum asserts that the decision supports the WEPCo interpretations (which apply the actual-to-potential interpretation to existing units which have begun "normal operations"), the decision, by its terms, only applies to installation of new emission units that have a greater capacity than the old units at an industrial facility. It does not apply to existing units that have begun normal operations.

(Footnote cont'd.)

to lower polluting natural gas is unlawful without a cap on current operations or a PSD permit.[8/] Indeed, participation in the Administration's Clean Coal program can, under these decisions, trigger new source requirements,[9/] as can any work on pollution control equipment that will "reduc[e] unit maintenance and downtime . . . [and] enhance the reliability of the pollution control device."[10/]

For the reasons discussed below, the policy implications of the WEPCo interpretations are immense.

- The WEPCo interpretations are inconsistent with the assumptions used in the economic evaluations of acid rain proposals performed for EPA over the past six years and relied upon by the Administration in formulating its acid rain proposals and in supporting them in Congressional testimony and public statements.[11/] If these EPA analyses had assumed that the WEPCo

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(Footnote cont'd. from previous pg.)

Moreover, the First Circuit suggests that the actual-to-potential interpretation affirmed by the court in the context of new cement kilns may not be reasonable as applied to utilities. Id. at 297-98.

8/ See supra note 3.

9/ See supra note 4.

10/ Memorandum from J. Calcagni, Director of EPA Air Quality Management Division, to D. Kee, Director of EPA Region V Air and Radiation Division (November 3, 1989) (Attachment 3). See infra note 22.

11/ See infra note 14.

interpretations would be enforced, the President could not have concluded that his proposals could be implemented in a flexible, cost effective manner.

- The WEPCo interpretations, if enforced, could increase the cost of the Administration's acid rain legislative proposals by billions of dollars. The interpretation would preclude utilities from achieving "required reductions in the most efficient and least costly manner," as promised in the President's June Fact Sheet on the acid rain proposals.12/

- The WEPCo interpretations, if enforced, will threaten the electricity supply of 118 million Americans in the mid-nineties, by preventing or delaying repairs needed to maintain an acceptable level of reliability at existing plants.

- The WEPCo interpretations are presently inhibiting the development of clean coal technologies, contrary to the President's intent to "encourage development of clean coal technology . . . and other cost effective means of using new technology to cut pollution."13/

- The WEPCo interpretations are already discouraging voluntary switches from oil to much lower polluting natural gas and conversions to coal-gas firing, and voluntary refurbishment of existing pollution control equipment.

12/ The White House, Office of the Press Secretary, "Fact Sheet: President Bush's Clean Air Plan," at 3 (June 12, 1989).

13/ Id. at 2.

- The WEPCo interpretations, if enforced, will prevent the industrial sector from modernizing plants to maintain or to restore their productivity and efficiency.

DISCUSSION

I. THE WEPCO INTERPRETATIONS ELIMINATE ANY CREDIBILITY TO THE ADMINISTRATION'S PROJECTIONS OF ACID RAIN-RELATED COSTS.

Since we wrote you in March, the Administration developed its "acid rain" legislative proposals based in large part on extensive economic analyses performed for the Agency by the consulting firm ICF, Inc. The President relied on these analyses in developing the acid rain proposals and used them in his "fact sheet" summarizing the economic impact of a flexible "market based" approach to SO_2 reductions. EPA has relied upon these ICF analyses in congressional testimony and in public statements. They are the foundation for the Administration's belief that a 10 million ton reduction in SO_2 emissions can be achieved in a cost-effective manner.

In these and past analyses of the Administration's acid rain bill, the Agency assumed (1) that every power plant would, at age 30, undertake a major refurbishment; (2) that these refurbishments would extend power plant life for 25 to 35 years; and (3) that the refurbishments would not trigger new source requirements.[14/] These assumptions, however, are contrary to the WEPCO interpretations which make clear that major refurbishments

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14/ See letter from K.A. Schweers, ICF, to R.A. Beck, EEI (July 25, 1989) (Attachment 4).

to extend unit life trigger new source requirements.[15/]

To analyze the implications of the WEPCo interpretations for the proposed acid rain legislation, UARG had ICF repeat its acid rain analyses, assuming that refurbishments would trigger new source requirments at older plants.[16/] ICF's analysis for UARG shows that the WEPCo interpretations would increase acid rain compliance costs by 1.0 to 7.2 billion dollars annually, depending upon how broadly the WEPCo interpretations are applied.[17/]

This massive increase in cost would occur, according to the ICF analyses, without any additional SO_2 reductions.[18/] This is because the WEPCo interpretations are enforced on a unit-by-unit basis, requiring installation of pollution control technology

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15/ See supra note 2.

16/ ICF Resources, "Analysis of the Potential Cost, Environmental and Energy Implications of EPA's Recent WEPCo and Greenwood Decisions" (January 1990) (Attachment 5). The ICF analyses for UARG used the same model, approach, and control cost assumptions used in the EPA analyses. One set of base case assumptions was developed reflecting the midrange of EPA's high and low emission base cases. The regulatory assumptions for UARG's acid rain case, however, were developed before the Administration's proposals were finalized and therefore are similar but not identical to the current Administration bill. Nonetheless, the forecasted emission reductions and electric utility costs under the "acid rain base" used in the UARG analyses falls within the mid range of recent ICF analyses of pending legislation performed for EPA.

17/ ICF Report at 12.

18/ Id. at 3.

(e.g., scrubbers) even at older, smaller units where such controls are not cost effective. As a result, rather than allowing utilities to achieve reductions at the units that can be controlled at the lowest cost, as contemplated in the Administration's proposal, the WEPCo interpretations would eliminate flexibility by requiring cost-ineffective control of specific units. Thus, the WEPCO interpretations would, contrary to the President's intent, require reductions to be achieved through a "command and control" approach rather than achieving "required reductions in the most efficient and least costly manner."[19/]

II. THE WEPCO INTERPRETATIONS UNDERMINE THE CLEAN COAL TECHNOLOGY PROGRAM AND DISCOURAGE VOLUNTARY EMISSION REDUCTIONS.

The WEPCo interpretations directly threaten another important Administration policy: encouraging the rapid development of "clean coal" technologies. In the Ohio Edison and other letters to utilities considering clean coal projects, your staff has taken the position that while installation and removal of a demonstration project would trigger new source requirements, EPA might be willing to promise not to enforce the law as EPA now interprets it.[20/]

19/ President's Fact Sheet, supra note 12, at 3.

20/ See supra note 4. See also Letter from John S. Seitz, Director of EPA Stationary Source Compliance Division, Office of Air Quality Planning and Standards, to Charles H. Goodman, Southern Company Services (July 21, 1989); Letter from Donald R. Clay, Acting Assistant Administrator for Air and Radiation, to David L. Feltner, Ohio Edison (April 27, 1989).

The offer of these promises not to bring a civil action for violation of the law (the so-called "no action assurance" letters) is no substitute for a reasonable interpretation of the new source rules that would facilitate development of environmentally beneficial technologies. To say the least, utilities will be extremely reluctant to participate in a program that requires them to accept the risk of a citizen suit or even criminal enforcement by the Department of Justice as the price of participation.

In addition to the clean coal program, the WEPCo interpretations are hostile to voluntary fuel conversions to lower polluting natural gas, as reflected in the Detroit Edison case.[21/] They have even led your staff to scrutinize intensely a proposal to improve existing control equipment performance at a power plant, on the grounds that properly functioning pollution control equipment will "reduc[e] unit maintenance and downtime."[22/]

21/ See supra note 3.

22/ Calcagni Memorandum, supra note 10. In this case, the utility proposed changes to its particulate control technology to improve the reliability and efficiency of that equipment. EPA Region V reached a preliminary determination that such work "do[es] not require a review under the PSD regulations." The Region further observed that "to our knowledge, this type of review has never been imposed on sources which have been required to come into compliance with SIP requirements, either voluntarily, or through enforcement actions." Letter from David Kee, Director of Air and Radiation Division, Region V, to Gerald Emison, Director of EPA Office of Air Quality Planning and

(Footnote cont'd.)

Until the WEPCo interpretations, industry was free to test, repair, improve, and install control technology, or to switch to lower polluting fuels, without any question being raised as to those activities triggering new source requirements. Interpreting new source rules in a manner which discourages improvements in pollution controls is wholly irrational and represents an absurd environmental policy.

Under these interpretations, for example, a utility proposing to comply with acid rain legislation by installing or upgrading pollution control equipment would, at the very least, have to undergo a potentially lengthy new source "applicability" review by your staff. Depending upon the outcome of that review, the utility could then be required to obtain a new source permit before installing control equipment. This would completely undermine efforts to achieve cost effective implementation of any acid rain control program and conflicts directly with the President's intent to encourage "clean coal technology . . . and

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(Footnote cont'd. from previous pg.)

Standards (September 1, 1989), enclosing draft response to Charles W. Kern, Northern Indiana Public Service Company (September 1, 1989). Your staff disagreed, observing that even if "the only effect of the change is to enhance the reliability of the pollution control device . . . the proposed change must be reviewed for prevention of significant deterioration (PSD) applicability purposes." Calcagni Memorandum, supra note 10 (emphasis added). The staff therefore asked for detailed information and proposed to "continue to work with the Region in analyzing . . . [the] applicability determination" for this facility. Id. The EPA staff therefore has put on hold work to improve the operation of this pollution control equipment.

other cost effective means of using new technology to cut pollution."[23]

III. THE WEPCO INTERPRETATIONS THREATEN THE RELIABILITY OF THE ELECTRIC SUPPLY IN THE EARLY AND MID-1990S.

As is clear from statements made by your staff, any repair or replacement that will "provide an economic incentive"[24] to increase production is the target of "EPA's recent activist" new source policies.[25] Projects that make plant operations more attractive from an economic standpoint include any project designed to restore reliable operations or to improve efficiency. As a result, if the WEPCo interpretations were enforced, projects to maintain or to restore operations at acceptable levels could not be undertaken without the utility either meeting new source requirements or accepting permit restrictions limiting production to current levels.

Accordingly, if the WEPCo interpretations were enforced, even minor repairs or replacements would likely be preceded by a request that EPA determine whether the repair or replacement could be undertaken without a permit. In the case of WEPCo, it took the Agency 16 months to process such an "applicability" request.

If a project triggers new source requirements (a likely

23/ President's Fact Sheet, supra note 12, at 2.

24/ Foote Memorandum, supra note 7, at 1.

25/ Id. at 3 (emphasis added).

result given the breadth of the WEPCo interpretations), a utility would have four options: (1) abandon the project and accept deterioration in efficiency and reliability of the unit; (2) shut down the unit if the repair was needed to operate; (3) accept a "cap" based on prior operations and delay repairs until that cap could be incorporated into a federally enforceable permit; or (4) undergo a new source review that could take two years or more.

Each of these alternatives has serious implications for maintaining a reliable electric supply in the early to mid-nineties. Each, including the option of asking your staff for an "applicability" determination, will constrain or prevent repairs or, at a minimum, will delay those repairs for a year or more. This will lead to less reliable operations, and even forced shutdown of units needed to meet demand.

To evaluate the potential electric reliability consequences of the WEPCo interpretations, UARG retained a nationally known expert on forecasting electricity supplies, Applied Economic Research Company (AER), to determine whether enforcement of these interpretations could lead to electricity shortfalls in the early-to-mid 1990s. 26/ The AER study shows that the WEPCo

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26/ AER is an energy forecasting firm that has been active in tracking electricity supply and demand, and in evaluating electricity supply and demand through the 1990s. AER has produced studies analyzing the supply of and demand for electricity, and the reliability, efficiency, and aging profile of steam electric plants, for the Department of Energy, Argonne National Laboratories, the National Electric Reliability Council,

(Footnote cont'd.)

interpretations could seriously frustrate the efforts of electric utilities to meet projected demand for electricity through the mid-1990s.

In order to provide a reliable supply of electricity, utilities typically plan to provide sufficient capacity to meet projected demand, to allow for plant outages, and to provide an "operating margin" of at least 2-3 percent to account for

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(Footnote cont'd. from previous pg.)

the Electric Power Research Institute, and for individual utilities, equipment manufacturers, fuel suppliers, and independent power producers.

For purposes of its study here, AER developed a model to analyze trends in availability and capacity as units age, both with and without cost-effective repair, replacement, and maintenance programs. Based on data regarding planned additions and retirements of utility boilers through the year 1995, AER then forecasted the impacts of unit aging and of the ability to conduct cost-effective repairs and replacements on the availability of installed generating capacity. A full description of the model, the data inputs, and assumptions will be provided to the Agency shortly in a report prepared by AER.

Briefly, the AER study examined two scenarios affecting electric supplies through 1995. In the first scenario, utilities would continue cost effective repair and replacement programs to maintain or to restore continued reliable and efficient operation of existing plants. In the second scenario, cost-effective maintenance programs would be restricted, so that the reliability of utility plants would decline. They would as a result operate at progressively lower capacity levels after 25 years of age, and they would be forced to retire after 45 years of age. The tables attached as Attachment 6 summarize the results of the AER forecasts for 1991-1995 for the twenty-one regions and subregions established by the National Electric Reliability Council (NERC). A map of the NERC regions is also included.

uncertainty in demand projections or in outage time. To maintain a 2 percent "operating margin," a utility would typically have to maintain a "reserve margin" of 20 to 25 percent.

Based on forecasts developed by the National Electric Reliability Council (NERC), four NERC subregions (i.e., subregions currently predicted to have an operating margin below 2 percent) will have to make extraordinary efforts over the next several years to maintain reliable service, even if utilities are allowed to continue undertaking cost-effective repair, replacement and maintenance programs.[27/] If utilities are not able to conduct cost-effective programs to maintain or to restore efficient operation at existing units (a result that would flow inexorably from the WEPCo interpretations), however, nine NERC subregions out of 21 subregions will fall below a 2 percent operating margin, threatening the maintenance of reliable service in the mid-1990s.[28/] According to the AER study, therefore, the WEPCo interpretations could adversely affect the reliability of the supply of electricity to up to 118 million people that live in the nine NERC subregions potentially impacted by these decisions.[29/]

27/ See Attachment 6, Table 3, column 1.

28/ See id., column 2.

29/ These results use NERC's projections of growth in electricity demand, which are much lower than those used by federal agencies such as DOE and EPA. If electricity demand grows more quickly, these impacts on the reliability of the electricity supply will extend, by the mid-1990s, to 12 NERC subregions, which contain 138 million people. See id., column 4.

Interruptions in service can adversely affect the public health and welfare in a profound way. As the Federal Power Commission noted in 1970:

> It is beyond dispute that electrical energy is the life-line of the city. Without it, no water could be pumped in many of its multi-storied buildings, subways and elevators could not operate, its refrigeration and food storage facilities would collapse, its streets would become dark and dangerous, its commerce stagnant, and the very health, safety and welfare of its occupants untenable . . . . The Northeast blackout in November 1965 -- affecting about 30 million persons in six states and in Canada -- was a spectacular reminder of how vital an uninterrupted flow of electric power is to their safety, defense, health and convenience.30/

The electricity supply impact of the WEPCo interpretations, which are hostile to maintaining a reliable supply of electricity, is a crucial consideration for any agency charged with protecting the public health and welfare.

30/ Consolidated Edison Co., 44 F.P.C. 350 (1970), aff'd, Scenic Hudson Preservation Conference v. FPC, 453, F.2d 463 (2d Cir. 1971), cert. denied, 407 U.S. 926 (1972).

IV. THE WEPCO INTERPRETATIONS DISCOURAGE PRODUCTIVITY AND PROMOTE INEFFICIENCY.

From a broader perspective, your staff has only recently concluded that work designed to "reduc[e] unit maintenance and downtime" and "to enhance the reliability of . . . pollution control" may trigger new source review.[31/] This conclusion was announced in the context of a proposal to upgrade pollution control equipment, something that has been going on for years under the Clean Air Act regulatory programs without any "new source" regulatory consequences.

This "recent activist" (as characterized in the Foote Memorandum)[32/] effort of your staff to expand the new source programs strikes at the heart of American industry. If every project undertaken to reduce downtime and improve efficiency or productivity can no longer be undertaken without EPA review and approval or serious regulatory consequences, both involving significant delay, American industry will find it difficult, if not impossible, to compete in world markets. These interpretations are hostile to a national economic policy that encourages efficiency, productivity, competitiveness, and improved environmental control.

31/ Calcagni Memorandum, supra notes 10 & 22.

32/ Foote Memorandum, supra note 7 at 3 (emphasis added).

CONCLUSION

Since we wrote you in March, your staff has not moderated these decisions and has taken steps to enforce the WEPCo interpretations retroactively across the utility industry.[33] It has also produced additional determinations hostile to the Clean Coal program and other pollution control efforts.[34]

Given the adverse consequences to the public, the economy,

33/ Your staff has only recently prepared to send an extensive survey addressing so-called "life extension" activity to the entire utility industry, and perhaps to industrial sources as well. Proposed EPA Information Collection Request No. 1545.01, supra note 6. The request is 11 pages in length, and asks a long list of unit-specific questions concerning maintenance projects undertaken by the industry. Moreover, your staff describes the activity covered by the request as including "changes in material selection and minor component replacements and design changes as well as general rehabilitation of existing equipment." Id., EPA Staff Justification at 1 (emphasis added).

The utility industry has over 2,000 individual boilers subject to this survey. The utility industry spends about $20 billion annually on maintaining these boilers. This maintenance activity involves hundreds of thousands, if not millions, of individual pieces of equipment. Given the breadth of this survey, the Agency will be confronted with mountains of information on maintenance activity if this request goes out.

It is not clear that the Agency has either the resources or the authority to collect and to use all of this information. For example, your staff asserts in justification of the request that it will assist the Agency in determining if facilities have been complying with the new WEPCo interpretations. It would be unprecedented, however, for an agency to attempt to apply such radical new interpretations retroactively for a 10 year period!

34/ See supra notes 20 and 22.

and the environment that would flow from enforcement of the WEPCo interpretations, we request that you reconsider these interpretations on an expedited schedule and that UARG be given an opportunity to meet with you to discuss its concerns.

Very truly yours,

Henry V. Nickel
F. William Brownell
Craig S. Harrison

Attachments (6)

cc: F. Henry Habicht, II, Esquire
Mr. J. Clarence Davies
William G. Rosenberg, Esquire
E. Donald Elliott, Esquire

Appendix II

Additional Material Submitted for the Record

SENATE SUBCOMMITTEE ON

MINERAL RESOURCES DEVELOPMENT AND PRODUCTION

May 8, 1990

HEARING ON

S. 1848

ESTABLISHING A RESEARCH AND DEMONSTRATION PROGRAM TO PROMOTE CO-FIRING OF NATURAL GAS AND COAL

STATEMENT BY

Flynt Kennedy, Vice President Research and Development

CONSOLIDATION COAL COMPANY

4000 Brownsville Road

Library, PA 15129

Submitted May 4, 1990

Consolidation Coal Company (Consol) is pleased to be invited to submit a statement on S. 1848, a bill which would establish and authorize a $6 million research and demonstration program to promote co-firing of natural gas and coal. Consol is headquartered in Pittsburgh and is the nation's second largest coal producer; we operate in Kentucky, West Virginia, Pennsylvania, Illinois, Tennessee, Ohio, Virginia and Utah. Our Research and Development Department employs 151 personnel, including 78 professionals, and is the largest R & D organization in the coal industry.

As Senator Ford knows, we have taken a keen interest in claims by the gas industry that there is a new technology, natural gas co-firing, which can help the coal industry. We have investigated and tested this hypothesis rather extensively and remain unconvinced of the purported benefits at this time.

We do not oppose the S. 1848. We propose that there should be changes in the bill's findings and definitions sections to make them factually accurate.

Changes Which Should Be Made in Section 2, "Findings":

"(d) Certain technologies combine natural gas with coal ~~in order to~~. This will reduce sulfur dioxide (SO_2), ~~and~~ nitrogen oxides (NO_x) ~~emissions, particulates~~ and carbon dioxide (CO_2) emissions and may reduce particulate emissions from the combustion of coal; and this may improves the ~~operating efficiency~~ operation of some boilers by reducing slagging."

[NOTE: Key Findings (d) -- Emissions Reduction and Efficiency Improvement.
By using 15% natural gas in a coal-fired boiler SO_2 emissions are reduced 15% by dilution (there generally is no sulfur in natural gas). On the other hand, flue gas desulfurization (scrubbers) are capable of SO_2 reductions of 95-98%, or at least six times greater. NO_x reductions with the same 15% natural gas are only 7.5% for co-firing but increase to 50% when "reburning" is employed. Low NO_x burners can reduce NO_x emissions by 45 to 60%. Reburning with 25% coal can also reduce NO_x by 50%. Natural gas usage will not necessarily reduce particulate emissions and may even result in an increase with electrostatic precipitators designed for high sulfur coals. Reduction of CO_2 emissions by gas co-firing are small on either a U.S. or global basis. Boiler efficiency actually decreases because natural gas generates more water than coal does during combustion. Slagging is adequately controlled without co-firing by proper adjustment of boiler operating parameters and/or switching to a better quality coal.]

"(e) certain technologies offer the potential to extend the usable coal resource base in the United States; and"

[NOTE: We have no problem with this finding because it is not restricted to co-firing. Because natural gas is a clean, high-value resource, it should be used primarily in residential, transportation, and chemical feedstock markets. There are better technologies, e.g., coal gasification combined cycle, pressurized fluidized bed combustion, etc., that offer the potential of extending the usable coal resource base through efficiency improvements.]

Changes to Section 2 -- continued:

"Therefore, it is in the national interest to explore, research, and evaluate ~~encourage~~ the utilization of those natural gas technologies that reduce SO_2 and NO_x emissions resulting from the combustion of coal."

[NOTE: Compared to coal, natural gas is not an "abundant" domestic resource. There are questions about availability, transmission capacity, and price that would prevent natural gas from being a reliable electric utility fuel. At current production levels, recoverable reserves can supply coal for at least 250 years versus a 30-35 year supply of natural gas at current production levels. Proven natural gas reserves represent a supply of less than ten years. Significant price increases are required to replace production with new discoveries.

Changes which should be made in be made in Section 3, "Definitions.":

"(b) The term 'gas reburn' means the injection of natural gas, coal, or oil into the region above the furnace burner zone ~~upper-furnace region~~ of an electric utility or an industrial boiler to produce a fuel-rich zone ~~thereby~~ for the destruction and reduced formation of ~~reducing~~ nitrogen oxide emissions; and"

[NOTE: These technical changes are needed to make the definition accurate.]

GENERAL DISCUSSION

At this point in time, Consol believes that natural gas co-firing is not as cost or performance effective as alternative approaches using coal alone. This conclusion is based on our study evaluation of emission control strategies in a baseload 500 MW power station firing 3% sulfur coal. Two important boiler types, wall-fired and cyclone-fired, were examined in our study. Sensitivity analysis proves that the coal-based options are less expensive than co-firing over a wide range of

plant capacity factors, sizes, and coal sulfur contents. Furthermore, plants opting for natural gas-based emission control strategies will operate at lower capacity factors under the constraint of economic dispatch. Use of natural gas does result in small reductions of CO_2 emissions (5.5%) on a unit-by-unit basis, but these are trivial on a U.S. or global basis.

Economics

The natural gas-based emission control options are 15% co-firing (7.5% NO_x and 15% SO_2 reduction) and 15% reburning (50% NO_x and 15% SO_2 reduction). Limiting the amount of natural gas to 15% avoids operating problems and derates that could arise because of dissimilar performance characteristics between gas and coal in a coal-fired boiler. Coal-alone alternative strategies are low NO_x burners (50% reduction) and coal reburning (50% reduction) for NO_x control and lower sulfur coal (15% reduction) or flue gas desulfurization/scrubber (90% reduction) for SO_2 emission control. Combining coal-alone options will simultaneously reduce NO_x and SO_2 emissions. A small reduction in the coal sulfur content by blending or coal switching (to 2.56% from 3%) gives SO_2 emissions reductions equivalent to co-firing or reburning with 15% natural gas.

Table 1 shows the reduction levels per megawatt-hour of power generated and the 20-year 1988 constant dollar levelized control costs

for both wall-fired and cyclone-fired power stations. Costs are shown for SO_2 and NO_x, separately and combined.

TABLE 1
Emission Reduction Cost

Option	Levelized Cost $(1988)/ton		
	NO_x	SO_2	$NO_x + SO_2$
Wall-Fired Unit			
15% Natural Gas Co-Firing	9646-10287	1019-1087	922-983
Lower Sulfur Coal	---	125-501	121-461
Low NO_x Burners	88	---	---
FGD	---	335	---
FGD/Low NO_x Burners	---	---	308
Cyclone Unit			
15% Natural Gas Reburning	1236-1311	1140-1209	593-629
25% Coal Reburning	303	---	---
Lower Sulfur Coal	---	125-501	210-415
FGD	---	335	---
FGD/Coal Reburning	---	---	330

For both boiler types, the coal-only strategies provide emission reduction at lower cost than the natural gas based strategies regardless of whether the targeted reduction is for NO_x, SO_2, or both. The range of costs shown for lower sulfur coal use represents a low and a high price premium for reduced sulfur content.

CONCLUSION

We commend the Subcommittee's interest in technologies which may make coal resources more useful in tomorrow's society. I am sure the Subcommittee will consider the proper way to make its authorized projects complementary with co-firing research being undertaken this year by EPRI and with the two research projects awarded grants under the federal Clean Coal Technology project. Again, thank you for the opportunity to submit these comments. Please contact me if I may be of assistance.

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WILLIAM W. BERRY
Chairman and Chief Executive Officer

MAY 10 RECD

Dominion Resources

May 8, 1990

The Honorable Bennett Johnston
Chairman, Energy and Natural Resources Committee
United States Senate
Hart Senate Office Building
2nd & C Streets, N.E.
Washington, D. C. 20510

Dear Senator Johnston:

I am submitting these comments in connection with your hearings on the so-called WEPCO problem because that problem is part of a larger concern that I have with the acid rain provisions of the Clean Air Act Amendments.

My concern is that the efficiency benefits of the innovative market principles incorporated in the legislation will be substantially reduced by carry-over "command and control" policies adopted years ago that will affect both existing and new units.

The market approach, if allowed to work as intended, would enable utilities to meet the requirements of the legislation wherever and however they could do so at the lowest cost to their customers. The potential savings from this approach, which I strongly support, run into the billions of dollars.

In the case of existing units, utilities would improve the efficiency and/or increase the generation from existing units if it was economically advantageous to do so -- recognizing that they would need to acquire any additional allowances for SO_2 resulting from increased output through reductions at their other units or by trades, and that the units would need to meet the legislation's rate standard for NO_x emissions. (In addition, the non-attainment provisions may require controls for NO_x beyond those required in the acid rain section.) In general, any emissions increases from refurbished units would not be large, but, in any event, those units would have to meet ambient air standards. Utilities would make the most favorable economic choice by comparing the cost of the improvements plus the cost of the allowances with their other options, including the development of new units and the use or sale of the allowances from units to be retired.

Dominion Resources

In the case of new units, the utilities would decide the level of SO_2 control that would be most economical -- recognizing that any emissions not prevented at the new unit would need to be offset at their other units or by purchases. Utilities would not choose control levels at new units with higher marginal costs per ton than reductions at existing units, including those obtained through retirements.

The result would be that:

* Total SO_2 emissions would be controlled by the allowance system to comply with the legislation's emissions cap.

* Ambient air quality would be protected by the continuing need of refurbished and new units to meet ambient air standards.

* Clean air objectives -- both in terms of total emissions and ambient air quality -- would be met at the lowest cost.

Unfortunately, the legislation passed in the Senate and reported by the House Energy and Commerce Committee will not allow these desirable results. The problem is that the new market principles are superimposed on existing "command and control" policies of another era that will hinder, if not stifle, the cost savings of the market approach.

To correct the situation, I urge that:

* New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) requirements in their present form not be applied to refurbished units -- thus curing the "WEPCO problem".

In the absence of the Clean Air Act Amendments, the application of NSPS and PSD requirements when existing units are improved has a rational purpose. It reduces overall emissions by preventing increases from existing sources and by encouraging the replacement of those units with new low-emitting units. But in the context of an allowance system designed to achieve a 10 million ton SO_2 reduction, these requirements are no longer justified.

Dominion Resources

If the unit's operating life is extended, total SO_2 emissions from old and new units will be still governed by the legislation's cap on total emissions. Total emissions will not increase from extending the lives of existing units.

If the units' generation is increased, any increased emissions must be offset by reductions elsewhere. Congress debated the issue of increases in generation (capacity factors) at certain units and resolved the issue in favor of allowing such increases in generation as long as the utilities could obtain the needed allowances. Allowing refurbished units to be subject to the WEPCO decision is inconsistent with that determination. It will add to electricity costs with no environmental benefit.

I also urge that:

* Best Available Control Technology (BACT) requirements be removed for new units -- thus avoiding costly control strategies with no environmental benefit.

In the absence of a limit on total allowances, the BACT requirement contributes to a reduction in SO_2 emissions and has a useful purpose. But with the allowance cap, the BACT requirement merely determines where the reductions are made and at what cost since emissions at a new unit as well as increased emissions at an existing unit must be fully offset elsewhere.

The BACT requirement in the context of the allowance system will inevitably increase costs with no environmental benefits. Total emissions will be unchanged. Ambient air quality, visibility concerns, and PSD increments would be addressed directly on their own merits. Technology will continue to advance since cost pressures will cause utilities to continue to demand improved technology for emissions control at both new and existing units.

EPA claims that the allowance system will create market incentives for utilities to install controls providing for SO_2 removal in excess of 90 percent at new power plants. This may well be true, but we are unlikely to find out because the BACT requirement will prevent utilities from making these determinations on the basis of market incentives.

Dominion Resources

EPA's Region III recently proposed as BACT on a Virginia project a technology that resulted in a marginal cost of $2800 per ton for the additional SO_2 removed. This cost may be compared to a cost of about $900 per ton for the technology proposed by the applicant and EPA's own estimates that the cost of allowances will be between $750 per ton and $1500 per ton.

In the context of the allowance system, this particular example could result in increased costs -- ultimately borne by electricity customers -- of more than $5 million per year with no change in SO_2 emissions, assuming EPA's low estimate for allowance costs (SO_2 reductions), and over $3 million per year assuming the higher EPA estimate. (2700 tons of incremental SO_2 reductions from the proposed BACT at $2807 per ton less 2700 tons and SO_2 reductions at $750 per ton.) These costs are not trivial, even for a single project, and represent unmitigated waste.

In summary, removal of the BACT requirement, in combination with the elimination of the percentage reduction requirement already in the legislation, is essential to allow the full benefits of the market system for both existing and new units. At a minimum, refurbished units should not be subject to NSPS and PSD requirements.

I appreciate your consideration of these comments.

Sincerely,

William W. Berry